UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE COMMISSION

In the Matter of	)	
	)	
ENTERGY NUCLEAR OPERATIONS, INC.,	)	
ENTERGY NUCLEAR GENERATION	)	
COMPANY, AND HOLTEC	)	
DECOMMISSIONING INTERNATIONAL,	)	Docket Nos. 50-293 & 72-1044
LLC; CONSIDERATION OF APPROVAL OF	)	
TRANSFER OF LICENSE AND	)	
CONFORMING AMENDMENT	)	
	)	
(Pilgrim Nuclear Power Station)	)	

APPENDIX

APPLICATION OF THE COMMONWEALTH OF MASSACHUSETTS FOR A STAY OF THE EFFECTIVENESS OF THE NUCLEAR REGULATORY COMMISSION STAFF'S ACTIONS APPROVING THE LICENSE TRANSFER APPLICATION AND REQUEST FOR AN EXEMPTION TO USE THE DECOMMISSIONING TRUST FUND FOR NON-DECOMMISSIONING PURPOSES

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BEFORE THE COMMISSION

In the Matter of ENTERGY NUCLEAR OPERATIONS, INC., ENTERGY NUCLEAR GENERATION COMPANY, AND HOLTEC DECOMMISSIONING INTERNATIONAL, LLC; CONSIDERATION OF APPROVAL OF TRANSFER OF LICENSE AND CONFORMING AMENDMENT (Pilgrim Nuclear Power Station)	)	Docket Nos. 50-293 & 72-1044

SECOND DECLARATION OF WARREN K. BREWER

I, Warren K. Brewer, declare and state as follows:

1. I am an Executive Consultant for Four Points Group, Incorporated, an engineering consulting firm providing services related to the nuclear industry, including decommissioning cost estimating and planning, and cost analysis with respect to spent fuel management and disposition. I have over 40 years of experience in the nuclear industry and have been involved in decommissioning cost estimating and planning since 1989. I submit this declaration in support of the Commonwealth of Massachusetts' application for a stay of the Nuclear Regulatory Commission (NRC) Staff's actions to approve the application to transfer the Pilgrim Nuclear Power Station license and the request for an exemption to use Pilgrim's Decommissioning Trust Fund for site restoration and spent nuclear fuel management costs. Without repeating them, this declaration includes, as if fully set forth herein, my declaration of February 18, 2019.[1]

[1] Declaration of Warren K. Brewer dated February 18, 2019 submitted in support of Commonwealth of Massachusetts Petition for Leave to Intervene and Hearing Request, Docket Nos. 50-293 and 72-1044, February 20, 2019 (ADAMS Accession No. ML19051A114).

2. I have a B.S. in electrical engineering from Louisiana Tech University and an M.S. in nuclear engineering from the Massachusetts Institute of Technology. I completed a graduate-level course of study in areas related to nuclear power and power plant design at the Bettis Reactor Engineering School. After obtaining my Master's degree, I worked for 10 years at the Division of Naval Reactors, the joint United States Department of Defense and Department of Energy organization responsible for all aspects of design, construction, maintenance, and operation of nuclear reactors in U.S. Navy ships and training facilities. I left the Division of Naval Reactors in 1986 and accepted a position with Pickard, Lowe and Garrick, a nuclear industry engineering consulting company. In late 1986, two colleagues and I formed ABZ. I now work with both ABZ, Inc. and Four Points Group. I have previously provided expert witness testimony related to engineering and the nuclear industry before state regulatory bodies, the United States Tax Court, the United States Court of Federal Claims (numerous cases), and in an international arbitration proceeding. Additional information about my background and experience is included in my curriculum vitae, which I have attached to this declaration as Exhibit 1.

3. I have reviewed filings related to the transfer of the Pilgrim Nuclear Power Station (PNPS or Pilgrim) from Entergy to Holtec, including the Revised Post-Shutdown Decommissioning Activities Report (PSDAR) and Preliminary Decommissioning Cost Estimate (DCE) submitted by Holtec to the NRC on November 16, 2018, the request for an exemption to use Pilgrim's Decommissioning Trust Fund for site restoration and spent nuclear fuel management costs, and Holtec's responses to NRC requests for additional information.[2]

[2] Throughout this affidavit Entergy shall be used to identify the Entergy entities including Entergy, Entergy Nuclear Operations, Inc and Entergy Nuclear Generating Company. Similarly, Holtec is used to refer to the Holtec entities including Holtec, HDI, Holtec Pilgrim and NamCo.

4. My testimony below is based on my experience in this field, and on information that is currently publicly available.

5. Based on my review of the publicly available information, if a stay is not issued, the NRC Staff's actions are likely to harm the residents and/or infrastructure of the Commonwealth of Massachusetts (Commonwealth), make it impossible to successfully complete the decommissioning of PNPS and safely secure for an indefinite period spent fuel onsite, or lead to irreversible consequences if the decommissioning approach is later altered due to regulatory action or financial concerns (which are likely to occur based on the presently available information and lack of controls on how Holtec may use Pilgrim's Decommissioning Trust Fund). Without limitation to other statements I could attest to and affirm, I specifically attest to and affirm the following as support for this statement.

6. NRC Staff's request for additional information (RAI), dated July 26, 2019 (ADAMS Accession No. ML19207B366) (RAI-PFPB-1) questioned the basis for use of a site-specific cost estimate in an amount less than the minimum required by 10 C.F.R. § 50.75 in demonstrating decommissioning financial assurance. NRC RAI-PFPB-2 requested Holtec to provide a revised cash flow analysis based on the 10 C.F.R. § 50.75 required minimum decommissioning cost. In its response dated July 29, 2019, Holtec provided a cash flow analysis that it contends shows adequate funding for decommissioning is available if the 10 C.F.R. § 50.75 minimum decommissioning cost is used instead of the site-specific decommissioning cost estimate Holtec utilized in the funding assurance calculation Holtec submitted to support the license transfer application. However, in addition to the difference in total cost, Holtec's revised cash flow analysis in response to the RAI-PFPB-2 was based on a different fundamental assumption from that applied in the cash flow analysis Holtec provided as part of the license transfer application.

7. Specifically, in its license transfer application, Holtec assumed a pre-tax 2 percent real rate of return, with the net earnings added to the decommissioning fund being this 2 percent real earnings less taxes paid on those earnings. As a result, the net real earnings in a given year were reduced by taxes to only about 1.4 percent of the fund balance. By contrast, the cash flow provided in response to RAI-PFPB-2 does not reduce earnings based on taxes due. It assumes that 2 percent earnings after taxes and above inflation are returned and added to the fund each year. In other words, with the same investment assumption, no provision has been made to account for taxes due on the earnings. An alternative interpretation of the new, unacknowledged Holtec assumption is that the assumed pre-tax earnings rate has increased from 2 percent real growth in the license transfer application to 2.8 percent real growth with the current cash flow. If the assumption used in the license transfer application cash flow analysis is applied in the RAI-PFPB-2 cash flow analysis such that taxes are properly accounted for and earnings are accordingly reduced, as was the case in its original site specific cost estimate, rather than calculating a remaining fund balance of about $11 million at the end of decommissioning, the analysis would result in a deficit of over $50 million. A spreadsheet showing this calculation is attached as Exhibit 2.

8. This projected deficit of over $50 million would be even larger had Holtec allocated the added costs proportionately over the license termination period. As Holtec stated in its RAI-PFPB-2 response, the difference in costs between the site-specific estimate used in Holtec's license transfer application and the minimum formula in 10 C.F.R. § 50.75 is about $41 million. Holtec allocated this difference in cost as a constant added cost to each year that includes license termination costs. However, Holtec does not cite to any guidance or reasoned basis indicating that this difference in cost will be uniformly charged and only in specific years. Absent an

analysis of the detailed costs and distribution of the costs through the decommissioning process as reflected in the 10 C.F.R. § 50.75 formula amount compared to the costs in the Holtec site-specific estimate, there is no basis to add a constant amount to each year of license termination work. It is at least as likely, if not more likely, that the difference in cost will be realized in a proportional manner throughout the duration of license termination work or realized almost entirely in the initial several years. Absent a detailed basis for distribution of the added costs, one of these two alternative distributions should be used because they would result in greater required funding, and therefore, greater assurance, than Holtec's method, which puts more of the added costs decades out near the end of decommissioning. If either of the two preferable distributions of added cost were to be used, the calculated funding deficit would be even larger than $50 million described above and detailed in Exhibit 2.

9. As noted by the NRC in RAI-PFPB-1, the funding assurance cash-flow analysis Holtec presented in its license transfer application is based on a license termination cost estimate less than the minimum funding amount set forth in 10 CFR 50.75(c). In responding to this RAI, Holtec argues that it may use a site-specific license termination cost estimate (DCE) that is less than the minimum amount 10 C.F.R. § 50.75(c) requires if it provides a basis for using the lower site-specific cost estimate. Holtec then asserts that it has provided such adequate basis by making various statements concerning how it calculated the lower estimated license termination costs. However, Holtec has not provided sufficient detail for independent evaluation of the validity of the DCE that it asks the NRC to accept for purposes of demonstrating financial assurance. For example, Holtec provides little detail as to the basis for costs associated with disposal of low-level radioactive waste. Holtec states that it will seek optimum terms for

disposal, which suggests the terms for disposal are not yet known.[3] However, some assumption about such terms must have been made for the purpose of the Holtec DCE because Holtec had to base its calculated cost for waste disposal on rates and terms for disposal of low-level radioactive waste. Yet, Holtec has provided no such details. Without such details concerning the Holtec DCE, no one can independently evaluate whether or not there is adequate basis for the use of the Holtec DCE to demonstrate decommissioning funding assurance. Additionally, Holtec did not include inventory tables summarizing the contaminated systems, components, rooms and/or areas requiring radiological decontamination as required by NUREG-1713 (pp.24-25) and exemplified in Tables 11 and 12 of NUREG-1713. NUREG-1713 directs the NRC reviewer to "compare the inventor provided with Table[s] 11 [and 12] to make a judgment regarding the reasonableness of the inventory." NUREG-1713 at 24. Holtec did not include this required information, and the NRC reviewer thus could not conduct any such review of this information in determining the adequacy of Holtec's DCE.

10. The Holtec site-specific cost estimate is based on performing cleanup sufficient to demonstrate a maximum of 25 mrem per year exposure from all pathways to allow termination of the NRC license for unrestricted use.[4] However, Holtec has not addressed that there are environmental cleanup criteria controlled by the Environmental Protection Agency (EPA) or Massachusetts state regulations in addition to the NRC requirements and that these other criteria would have to be met as well to completely remediate the Pilgrim site. Compliance with these other non-NRC requirements will require work beyond that assumed in the Holtec cost estimate. In order to comply with such non-NRC requirements, other facilities such as Yankee Rowe, also

[3] Holtec DCE at 26-27.
[4] Holtec DCE at 23.

located in Massachusetts, performed cleanup to a more stringent limit of 10 mrem per year for radiological contamination as well as satisfying cleanup criteria for non-radiological contaminates.[5] The cost for remediation to meet the non-NRC requirements is not included in the Holtec cost estimate used to demonstrate funding assurance.

11. NRC Staff also previously asked Holtec about its ability to manage concurrent decommissioning of two nuclear power plant sites, PNPS and Oyster Creek Nuclear Generating Station (Oyster Creek). In response, Holtec attempted to support its management capability by relying largely on retaining current senior plant leadership and operating experts who had been responsible for maintaining the plant during operation as well as post shutdown.[6] These senior plant leaders and operating experts are to be supplemented, according to Holtec, by additional existing plant staff to provide experienced teams at each site.[7] In April 2019, Entergy announced its plan to sell Indian Point Units 1, 2, and 3 (Indian Point) to Holtec. Assuming these projects all obtain regulatory approval, and there is no reason to assume otherwise based on the NRC Staff's approach to review of the Pilgrim and Oyster Creek license transfer applications, Holtec would begin decommissioning of the Indian Point Units following the transfer of ownership.[8] If effectuated, Holtec would be responsible for decommissioning as many as six reactors at four

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[5] Ltr from Michael J. Gorski, Regional Director, Commonwealth of Massachusetts Department of Environmental Protection, Western Regional Office to Yankee Atomic Electric Company, regarding Comprehensive Site Assessment Report for Yankee Nuclear Power Station, dated October 16, 2008, http://www.yankeerowe.com/pdf/MA_DEP_Phase_IIl.pdf.

[6] *Holtec Response to NRC Request for Additional Information*, April 17, 2019 (ADAMS Accession No. ML19109A177)

[7] *Id.*

[8] Entergy Press Release: Entergy Agrees to Post-Shutdown Sale of Indian Point Energy Center to Holtec International (Apr. 16, 2018), https://www.entergynewsroom.com/news/entergy-agrees-post-shutdown-sale-indian-pointenergy-center-holtec-international/.

nuclear power stations: PNPS, Oyster Creek, Palisades Nuclear Generating Station (Palisades),[9] and the three Indian Point reactors effectively all at the same time while also managing spent nuclear fuel at each of these facilities for an indefinite period.

12. To date, Holtec has not been responsible for the successful decommissioning of even one commercial nuclear power station in the United States. Holtec has not provided specific information for the NRC to evaluate its ability to act as owner, licensee, and decommissioning agent for six commercial nuclear reactors on schedule and within budget. The risk of failure is exacerbated by the projections showing over a $50 million shortfall in funding for Pilgrim alone with the assumptions in the license transfer application and the minimum formula decommissioning costs.[10] Additionally, the NRC has removed the requirement for PNPS to maintain a contingency fund of $50 million that was to be used, in part, to cover decommissioning costs.

13. No specific information has been provided to demonstrate Holtec's ability to acquire adequate staffing to decommission six reactors at the same time, particularly for specialized tasks such as reactor vessel and internal segmentation where there are a limited number of qualified and experienced vendors available, and to simultaneously manage the other decommissioning activities such as radioactive and hazardous waste shipments from multiple sites all while

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[9] Holtec Press Release: Holtec International to Acquire Pilgrim and Palisades Sites from Entergy after their Reactors Shutdown: Proto-Prompt Decommissioning Planned for Both Sites (Aug. 1, 2018), https://holtecinternational.com/2018/08/01/holtec-international-to-acquire-pilgrim-and-palisades-sites-from-entergy-after-their-reactors-shutdown-proto-prompt-decommissioning-planned-for-both-sites/

[10] NRC regulations allow a licensee to assume 2 percent real growth in trust fund assets to demonstrate financial assurance for decommissioning. However, if a trust fund is invested conservatively during decommissioning, obtaining a 2 percent real growth may be impossible. Such failure to obtain a 2 percent real growth would further exacerbate a decommissioning shortfall.

adequately controlling the schedule and budget for all of the parallel projects. NRC Staff's order approving the license transfer application does not analyze or even consider this lack of specific information.

14. Holtec has not considered the cost of SFM expenses in the virtually certain event that DOE fails to pick up the SNF within Holtec's predicted timeframe in its DCE. Assuming the possibility that DOE takes 120 years to pick up the SNF as suggested by Holtec in documents related to licensing an independent fuel storage facility, the cost for SFM could be a total of about $1.27 billion which is about $768 million more than the spent fuel management costs in the Holtec DCE. The added costs for storage beyond the 2063 date assumed by Holtec in its PSDAR would include the annual spent fuel managements costs as well as costs for repackaging the stored fuel after 100 years of storage. While not a requirement, the NRC in its evaluation of long-term dry storage of spent fuel has indicated that it should be assumed that spent fuel would need to be repackaged after 100 years. The repackaging costs would include four cost elements. These elements would be costs for construction of new facilities to be used for the repackaging, costs for new storage canisters, costs for labor to perform the repackaging and costs to dispose of the old fuel storage canisters as low level radioactive waste. New facilities would be needed because all the Pilgrim fuel handling facilities would have long been dismantled during decommissioning. It might be possible to transfer the spent fuel to a third party for repackaging, but that alternative would likely be at least as costly as building a transfer facility. For the purpose of my evaluation here, the cost of the new facilities were assumed to be $150 million, consistent with the lower end of the Government Accounting Office estimate for such facilities.[11]

[11] U.S. Government Accountability Office, GAO-10-48, Nuclear Waste Management: Key Attributes, Challenges, and Costs for the Yucca Mountain Repository and Two Potential Alternatives 55 (Nov. 2009), https://www.gao.gov/assets/ 300/298028.pdf.

The other costs have been estimated based on current costs for dry fuel storage hardware, storage cask loading and disposal of low-level radioactive waste. The estimated cash flow for spent fuel management extending 120 years after shutdown of PNPS is presented in Exhibit 3.

15. Holtec's cash flow for decommissioning Pilgrim shows expenses totaling over $138 million in 2019, and about $164 million in 2020, or over $303 million in the first 17 months of the Pilgrim project.[12] These expenditures total more than 29 percent of the initial available funding. Thus, if Holtec begins the Pilgrim decommissioning project and is not able to manage and execute six simultaneous decommissioning projects, it is possible that sufficient funding will not remain in the decommissioning trust funds to permit another vendor to complete the decommissioning work or to change the decommissioning approach. For example, if remediation of structures, systems and components (SSC) consistent with a prompt DECON decommissioning approach is started and a decision made to switch to a SAFSTOR approach, the initial decommissioning work may have altered not only those SSC being remediated but other SSC, leaving the plant in a condition incompatible with SAFSTOR. The work needed to return the plant to an acceptable state for SAFSTOR or delayed DECON could result in substantial costs not anticipated in the PSDAR or decommissioning cost estimate analysis. For example, if the DECON process is halted and a switch made to SAFSTOR after gaps or holes have been made in the containment but not all of the material has been removed from within the containment, the containment would not serve as a long-term weather-tight barrier to the spread of contamination, and remedial work would be required to return the containment to a condition consistent with SAFSTOR. Similarly, once holes and openings have been created in other

[12] *Holtec Response to NRC Request for Additional Information*, July 29, 2019, Attachment 1 to Enclosure (ADAMS Accession No. ML19210E470).

structures, after switching to a SAFSTOR approach, additional work would be required to restore structures to an acceptable state for long-term storage and prevent the otherwise uncontrolled accumulation and leakage of rain water during the SAFSTOR period, which could result in redistribution of contamination within the structures. Finally, all decommissioning must be completed within 60 years pursuant to 10 C.F.R. 50.82(a)(3). If the transfer is allowed and DECON is initiated, yet a decision to switch to a SAFSTOR is made in the future, there may not be sufficient time for the depleted decommissioning trust fund to earn enough interest to cover decommissioning costs associated with the switch.

16. The decommissioning activities proposed by Holtec will likely harm Commonwealth residents if the realistic scenario described above occurs or, as explained next, even if it does not. For example, frequent waste shipments over local roads will affect traffic flow, cause noise, dust, and pollution emissions, increase the possibility of accidents on local roads, and damage local infrastructure.[13] Holtec has estimated the radioactive waste volume to be over 1.4 million cubic feet. If shipped by truck, this could easily require more than 1,400 separate truck shipments just for radioactive waste alone.[14] 10 C.F.R. 50.82(a)(6) requires that no decommissioning activities

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[13] In section 5.1.17 of its PSDAR, Holtec assumes the Class A radioactive waste volume will be 1.4 million cubic feet, over six times the waste estimate assumed by Entergy in its PSDAR. Holtec asserts that this projected amount is bounded by the 1.5 million cubic feet assumed in the Decommissioning GEIS, yet the domestic decommissioning experience shows that radioactive waste volume is often significantly underestimated. Further, Holtec includes the conclusory assertion without any evidence whatsoever that shipment of this large amount of radioactive waste will not affect local traffic density or degrade infrastructure.

[14] Holtec PSDAR at 5.1.17. 1.4 million cubic feet at 60 pounds per cubic foot results in 84 million pounds of waste. Assuming legal weight trucks at 60,000 pounds of waste per truck results in 1,400 waste shipments. The 84 million pounds is the total Holtec waste estimate. By comparison, Maine Yankee generated about 84 million pounds of just soil waste and Connecticut Yankee generated about 87.5 million pounds of soil waste. *Connecticut Yankee Decommissioning Experience Report, Detailed Experiences 1996-2006*, ELECTRIC POWER RESEARCH INSTITUTE TECHNICAL REPORT 1013511 (Nov. 2006), at 7-13 and A-1; *Maine Yankee Decommissioning Experience Report, Detailed Experiences 1997-2004*, ELECTRIC POWER

that result in significant environmental impacts be performed unless previously reviewed by the NRC. The conservatively-estimated 1,400 separate truck shipments for radiological waste is more than double the 671 truck shipments evaluated in the NRC generic environmental impact statement for decommissioning.[15] No Pilgrim specific environmental assessment or impact statement has been produced to evaluate this significantly greater number of truck shipments of radioactive waste. In addition, neither Entergy nor Holtec provided information on the amount of non-radioactive waste that they will need to remove and ship off-site for disposal. However, experience from decommissioning of Maine Yankee and Connecticut Yankee identifies non-radioactive waste of 150 million pounds and 350 million pounds, respectively.[16] The additional truck shipments required for non-radioactive waste could increase the number well beyond the 1,400 shipments discussed above. Assuming the lower figure from non-radioactive waste from the Maine Yankee experience, the number of truck shipments over the roads near Pilgrim could be two to three times the 1,400 shipments discussed above. Legacy waste, waste generated during operation but which has been stored on site is typically removed and shipped within the first sixty days of DECON decommissioning to clear space on site since this material can be

RESEARCH INSTITUTE (prepared by New Horizon Scientific, LLC), at Table E-1, http://www.maineyankee.com/public/pdfs/epri/my%20epri%20report-2005.pdf. Based on experience from Maine Yankee and Connecticut Yankee it is likely that the total radioactive waste volume will be even larger than that estimated by Holtec. Maine Yankee experienced total radioactive waste of about 246 million pounds and Connecticut Yankee experienced total radioactive waste of about 265 million pounds.

[15] NUREG-0586, Supplement 1, Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities, Table 4-6 (Nov. 2002) (ADAMS Accession No. ML18057B048).

[16] *Connecticut Yankee Decommissioning Experience Report, Detailed Experiences 1996-2006*, ELECTRIC POWER RESEARCH INSTITUTE TECHNICAL REPORT 1013511 (Nov. 2006), at 7-13 and A-1; *Maine Yankee Decommissioning Experience Report, Detailed Experiences 1997-2004,* ELECTRIC POWER RESEARCH INSTITUTE (prepared by New Horizon Scientific, LLC), at Table E-1, http://www.maineyankee.com/public/pdfs/epri/my%20epri%20report-2005.pdf.

shipped off site with much less effort than material which must be removed from systems or structures. Thus, if the transfer is permitted to go forward, these waste shipments will begin immediately, causing damage to local and state infrastructure and interference with local quality of life and enjoyment.

17. Holtec indicated that delaying the license transfer decision will have an adverse effect on 270 individuals who work at Pilgrim. Holtec contends these 270 individuals will be kept in limbo as to whether they will be retained if the plant is transferred to Holtec and when such decision will be made. This unsupported assertion is not compelling. The plant personnel needed to maintain the plant will be retained for that purpose until the decision about transfer of the plant is finalized. Further, Holtec has not identified how many of the 270 personnel would be retained after license transfer to assist in the decommissioning, site restoration, and spent fuel management, but however many personnel Holtec decides to retain, that number of personnel is not dependent on the timing of the license transfer decision. The ultimate fate of the 270 personnel might be changed by personnel decisions, but it would not be different because of any delay in the license transfer decision.

18. Holtec also asserts that the uncertainty of the transfer of the plant may encourage some personnel to seek other opportunities elsewhere. The only reason that this can be a concern is if Holtec is uncertain that it can attract and hire qualified personnel to decommission the plant if the transfer occurs. If Holtec has concerns about its ability to attract and hire personnel because some fraction of the 270 Entergy personnel that Holtec might want to retain have moved on to other opportunities, then this would be significant basis for concern about the ability of Holtec to manage the concurrent decommissioning of six reactors as it is planning.

19. Given the very limited NDT balance projected by Holtec at the end of decommissioning, additional cleanup to satisfy non-NRC requirements for radiological and non-radiological site remediation could easily result in the decommissioning trust fund not being sufficient to provide for NRC defined license termination costs, spent fuel management costs, and site restoration costs. Assuming these additional site restoration activities are performed over the same period as the site restoration activities included in the Holtec cost estimate, an increase of as little five percent in the total site restoration costs would result in a decommissioning trust fund deficit if the Holtec-requested exemption to allow use of decommissioning trust funds for site restoration work is permitted. While the original purpose of the decommissioning trust fund was to provide funding for NRC license termination work, the requested exemption and added costs for work to comply with non-NRC regulations, which are not included in the Holtec cost estimate, could result in insufficient funds being available for the completion of NRC required license termination work. Without addressing the cost for this non-NRC regulated work that can be paid for with funds from the NDT, there is no assurance of adequate decommissioning funding.

20. The Holtec site-specific funding assurance is based on a calculation that assumes a 2 percent real growth rate before taxes for the decommissioning trust fund. Similar to a retirement account for a person approaching retirement, it is reasonable to assume that the investment strategy for a decommissioning trust fund would change as decommissioning advances to focus very largely or entirely on investments with essentially no risk such as U.S. Government Treasury obligations. The rate of return for U.S. Government Treasury obligations with durations of 1 to 10 years is currently no more than 1.9 percent.[17] Based on Bureau of Labor

[17] https://www.treasury.gov/resource-center/data-chart-center/interest-

Statistics for price inflation over the period of 2000 to 2019, the average rate of price inflation is about 1.75 percent.[18] Thus, for a NDT invested in U.S. Treasuries at 1.9 percent the pre-tax real rate of return would be about 0.15 percent (with the post-tax real rate of return being less than zero), much less than the 2 percent assumed in the Holtec funding assurance cash flow analysis. No information has been provided to demonstrate that the assumed real rate of return is consistent with Holtec's planned investment strategy. If the NRC ultimately accepts Holtec's site-specific cost estimate as the basis for demonstrating financial assurance (instead of the minimum formula required by NRC regulations), then Holtec's site-specific cost estimate should also use a company and purpose specific investment strategy as the basis for its site-specific cost estimate instead of the generic 2 percent allowed under the NRC's minimum formula.

21. I, Warren K. Brewer, have read the above statement consisting of 15 pages, and I certify under penalty of perjury that the foregoing is true and correct. Executed on September 3, 2019.

Warren K. Brewer

WARREN K. BREWER
Executive Consultant
Four Points Group, Inc.

rates/Pages/TextView.aspx?data=yield

[18] https://data.bls.gov/cgi-bin/cpicalc.pl for January 2000 through January 2019.

WARREN K. BREWER

EDUCATION

Bettis Reactor Engineering School, 1976

M.S., Nuclear Engineering, Massachusetts Institute of Technology, 1976

B.S., Electrical Engineering, Louisiana Tech University, 1974

EXPERIENCE

1986 - Present - ABZ, Incorporated and Four Points Group, Incorporated starting 2017

Executive Consultant specializing in nuclear power plant operations, decommissioning cost estimating and planning and severe accident analysis. This experience has included work related to regulatory compliance, inservice inspection and testing (ISI/IST), configuration management, procedure and technical specification reviews and design basis documentation.

More specifically, the experience in these areas has included:

Provided engineering and management services as part of an integrated team to validate and update the Southern California Edison San Onofre nuclear plant design basis documentation.

Managed the development of advanced computer systems for assisting nuclear plant staff in compliance with regulatory requirements. These systems assisted in scheduling of NRC required plant condition dependent surveillance testing, collecting and evaluating test data, managing of system operability information and plant license limiting conditions for operation, compliance with nuclear plant operator scheduling and overtime regulations, and compliance with NRC event reportability regulations. The surveillance test scheduling system was used by one utility for almost 20 years with no failures.

Developed methods for verification and validation of expert system computer codes based on industry guidelines and accepted criteria for conventional codes. Presented lecture to the NRC on methods of verification and validation as part of a lecture series on software quality assurance

Provided expert assistance to the programmers in developing a state-of-the-art desktop nuclear power plant simulator for training operators to learn and understand event-based Emergency Operating Procedures (EOPs).

Over 20 years experience in preparation and review of decommissioning plans and cost estimates. Participated in conferences and workshops on decommissioning costs and funding adequacy. Provided on-site monitoring of decommissioning activities.

Provided assistance concerning decommissioning costs, planning and progress as part of process to negotiate sale of a nuclear plant.

Conducted specific studies relative to projected costs of low-level waste disposal and spent fuel management providing the results to state agencies and companies in the nuclear industry.

Prepared reports for state regulators evaluating cost estimates for decommissioning, low-level waste disposal, and extended spent fuel storage. Provided training to state regulators on decommissioning technology and methodology of decommissioning cost estimating.

Developed methodology for evaluating costs for recovery from severe reactor accidents. This methodology has been used by the majority of the US nuclear industry, foreign utilities and nuclear insurers to advise them on potential losses and insurance recoveries as well as to assist risk managers in determining the coverage levels to obtain.

Performed evaluations of the liability claims that could arise from transportation of nuclear material. These evaluations included assessment of the technical conditions that might result from such events, the probability of such events, and all liability costs that might be incurred (cleanup, property damage, health effect, business interruption or losses, etc.).

Performed reviews of maintenance, operations, and quality assurance programs. Such reviews included comparison of the program elements with the regulations, evaluation of specific work packages and implementation of work in the field.

Provided DOE with expert assistance in evaluating the generic environmental impact statements for the New Production Reactor. This included verification and validation of offsite releases, environmental impacts, and the technical aspects of operation.

Managed and participated in the development of computer program for fluid flow analysis. The program is applicable to a wide range of facilities and industries. The program has been marketed world-wide since 1992 with an estimated 25,000 users.

Extensive experience in providing litigation support and expert witness services related to nuclear plant operation, decommissioning planning and costs, spent fuel management and general engineering. Expert testimony has been provided before the US Court of Federal Claims, US Tax Court, state regulatory agencies and arbitration tribunals.

This litigation support and expert witness experience has included:

Over 12 years experience in evaluation of claims resulting from the US Department of Energy's (DOE) breach of the contract with nuclear plant operators for the disposal of spent nuclear fuel. This has included evaluation of spent fuel storage options, dry storage facilities and cask designs, specific plant decisions, equipment, incurred costs and spent fuel transportation options. Prepared expert witness reports and provided expert testimony.

Provided rate case support in proceedings before state and federal regulators. Issues addressed included the adequacy of decommissioning cost estimates, as well as

prudence of operational actions, management effectiveness, technical soundness of operation, technical design basis and details, and regulatory compliance and adherence to industry standards. Work included testimony, as well as assisting in preparing data and information for testimony by others. Prepared reports for state regulators evaluating cost estimates for decommissioning, low-level waste disposal, and extended spent fuel storage. Provided training to state regulators on decommissioning technology and methodology of decommissioning cost estimating.

1986 - Pickard, Lowe and Garrick, Inc.

Consulting Engineer.

Conducted detailed review of technical specification surveillance test requirements for a nuclear power plant. This included detailed review of the implementing programs and procedures, and providing detailed comments for procedure revisions to ensure regulatory compliance.

Conducted detailed review of technical specification requirements, technical specification basis, regulatory background, industry practice, and implementing procedures at a nuclear power plant for required logic system functional testing and simulated automatic actuation testing of emergency core cooling systems and primary containment isolation.

Reviewed plant-specific probabilistic risk assessment (PRA). Along with general evaluation, provided assessment of operational considerations and/or lessons resulting from the PRA.

Participated in procedure review and upgrade project.

1982 - 1986 - United States Navy, Division of Naval Reactors

Head, Reactor Plant Systems - New Design Submarine.

Lead responsibility for reactor plant performance, safety, and quality.

Conducted various trade-off studies to establish overall design criteria for new design reactor and propulsion plant. This included evaluation of possible performance maintainability, survivability, constructability, and cost. Established general design characteristics for further development.

Evaluated various proposed core designs to determine optimum design to fit overall propulsion plant design goals. This included evaluation of thermal hydraulic performance, safety evaluation, normal plant response analysis, and reactor structural design assessment, including response under shock loading.

Reviewed and approved conceptual system designs, performance criteria, and detailed design bases. As design progressed, this included increasing levels of detail to system design descriptions, design calculations, component sizing, system schematics, and construction details.

Participated in design of major plant components to ensure structural soundness, compliance with overall design goals, and ability to interface with other systems and propulsion plant arrangement.

Reviewed and approved design of reactor plant structures, such as component foundations.

Reviewed and approved plant equipment and system arrangements.

Reviewed reactor and plant control system designs for compatibility with mechanical system designs and core performance and capabilities.

Reviewed and approved operating transient response predictions to be used in life-cycle evaluations of plant.

Developed life-cycle plant operating profile based on mission requirements and data from previous submarine classes.

Had lead responsibility for design initiatives to mitigate the consequences of complete loss of AC power and to ensure safety of surrounding population if this type event occurred near port.

Participated in extensive effort to reduce plant weight. Potential weight reduction concepts were each evaluated for its total effect on capability, constructability, life-cycle cost, and maintainability.

Participated in Naval Reactors crew quizzes for crews of operating submarines to test knowledge and ability of ship crew to safely and efficiently operate the propulsion plant. Responsibility was mainly for testing in the area of reactor plant mechanical system operation.

1980 - 1982 - United States Navy, Division of Naval Reactors

Head, Reactor Plant Systems - TRIDENT Submarines.

Supervised engineering group. Directed efforts concerning design, construction, operation, maintenance, testing, and configuration control of reactor plant fluid systems and structures for TRIDENT submarine. Similar duties in connection with land-based TRIDENT reactor plant prototype.

Responsible for shock design of shipboard reactor plant components and structures. Similarly, responsible for seismic design of structures, systems, and components unique to land-based prototype. Seismic design was done to the same criteria imposed on commercial nuclear power plants.

Developed IST/ISI program for land-based prototype conforming to ASME Code, Section XI. These programs were in compliance with the requirements imposed on commercial nuclear power plants.

Responsible for design, acceptance testing, operation and maintenance procedure for emergency core cooling system for the land-based prototype. This system was

designed to comply with NRC requirements imposed on commercial power plants for similar systems.

Responsible for preparation of reactor plant operating, maintenance, and test procedures.

Evaluated operation incidents and established corrective actions based on these evaluations.

Evaluated and resolved construction deviations from specified requirements.

Participated in examination of prototype operating crews to evaluate level of knowledge and capability to safely operate the reactor plant.

Responsible for design, construction, operation, and maintenance of support systems, such as process cooling water and associated cooling tower to support prototype operation.

1976 - 1980 - United States Navy, Division of Naval Reactors

Project Engineer, TRIDENT Class submarine propulsion plant design.

Coordinated government laboratory and shipyard work in all phases of design, construction, operation, testing, and maintenance of steam plant fluid systems for TRIDENT submarines and land-based TRIDENT submarine prototype.

Responsible for design of shipboard structures and piping systems in accordance with shock design criteria.

Responsible for preparation of verbatim compliance operating and maintenance procedures. This included performance of procedure verification and validation.

Responsible for design of safety systems unique to the land-based prototype, including compliance with NRC requirements for similar systems in commercial power plants.

Evaluated and resolved shipyard construction deviations for structures and systems.

Participated in the evaluation, analysis, and resolution of large-scale shipyard error resulting in unapproved material substitutions. This involved tracking and identifying where incorrect materials had been used, evaluating and testing the acceptability of the material as-built, and approving the as-built condition or specifying the required rework.

Testimony

State of New Hampshire Decommissioning Finance Committee hearing on the Seabrook Nuclear Power Plant decommissioning funding, 1994.

Mitsubishi Heavy Industries, Ltd (Japan) v. Finmeccanica S.p.A., Azienda Ansaldo (Italy), as successor in interest to Ansaldo S.p.A., International Court of Arbitration, Case Number 10269/OL/ESRT/TE, June 2001.

Tennessee Valley Authority v. United States of America, Case No. 01-249C, July 2005.

SFI Mississippi v. United States of America, Case No. 03-2624C, September 2006.

Boston Edison v. United States of America, Case No. 99-447C and 03-2626C, June 2007.

Wisconsin Electric v. United States of America, Case No. 00-697C, September 2007.

Dairyland Power Cooperative v. United States of America, Case No. 04-0106C, July 2008.

Entergy Corporation and Affiliated Subsidiary Companies v. Commissioner of Internal Revenue, Docket No. 10557-08, June 2008.

Consolidated Edison Company of New York, Inc. v. United States of America, Case No. 04-33C, June 2009.

Entergy Nuclear Indian Point 2, LLC v. United States of America, Case No. 03-2622C, June 2009.

Entergy Nuclear Generation Company v. United States of America, Case No. 03-2626C, September and October 2009.

Entergy Nuclear Vermont Yankee, LLC v. United States of America, Case No. 02-898C, March and April 2010.

Portland General Electric, the City of Eugene Oregon, and Pacificorp v. United States of America, Case No. 04-0009C, November 2011.

System Fuels, Inc. and Entergy Arkansas, Inc. v. United States, Case No. 03-2623C, October and November, 2012.

State of Vermont Public Service Board, Docket No. 7862, Petition for Amendment of Certificate of Public Good for Vermont Yankee Nuclear Power Station.

System Fuels, Inc. and Entergy Arkansas, Inc. v. United States, Case No. 12-389C, July 2014.

System Fuels Inc., System Energy Resources, Inc., and South Mississippi Electric Power Association v. United States, Case No. 11-511C, October 2014.

Entergy Gulf States, Inc. and Entergy Gulf States Louisiana, LLC. V. United States, Case No. 03-2625C, May 2015.

Entergy Nuclear FitzPatrick, LLC., Entergy Nuclear Indian Point 3, LLC., and Entergy Nuclear Operations, Inc. v. United States, Case No. 03-2627C, August 2015.

Entergy Nuclear Indian Point 2, LLC v. United States, Case No. 13-19C, April 2016.

Sacramento Utility District v. United States, Case No. 15-577C, October 2016.

State of Vermont Public Utilities Commission, Docket No. 8880, Joint Petition to Transfer Ownership of Entergy Nuclear Vermont Yankee, May 2018.

Year	License Termination (LT)	Added LT For Minimum	Total LT	Spent Fuel Costs (SF)	Site Restoration (SR)	Total Annual Expense	Year Starting NDT Balance	NDT Withdraw	Remaining NDT After Expense	NDT Earnings After Tax (2)	Year End NDT Balance
2019	$84,927,494	$3,701,293	$88,628,787	$53,919,755	$17,619	$142,566,161	$1,030,000,000	-$142,566,161	$887,433,839	$5,250,650	$892,684,489
2020	$79,292,448	$3,701,294	$82,993,742	$84,905,227	$27,597	$167,926,566	$892,684,489	-$167,926,566	$724,757,923	$10,291,563	$735,049,486
2021	$46,758,773	$3,701,294	$50,460,067	$82,500,059	$636,985	$133,597,111	$735,049,486	-$133,597,111	$601,452,375	$8,540,624	$609,992,998
2022	$103,197,395	$3,701,294	$106,898,689	$3,331,593	$23,629,849	$133,860,131	$609,992,998	-$133,860,131	$476,132,867	$6,761,087	$482,893,954
2023	$167,453,076	$3,701,294	$171,154,370	$3,135,304	$1,699,521	$175,989,195	$482,893,954	-$175,989,195	$306,904,759	$4,358,048	$311,262,807
2024	$95,693,887	$3,701,294	$99,395,181	$3,225,310	$9,235,554	$111,856,045	$311,262,807	-$111,856,045	$199,406,762	$2,831,576	$202,238,338
2025	$1,309,633	$3,701,294	$5,010,927	$6,306,278	$4,126,523	$15,443,728	$202,238,338	-$15,443,728	$186,794,610	$2,652,483	$189,447,093
2026	$0	$0	$0	$5,952,309	$0	$5,952,309	$189,447,093	-$5,952,309	$183,494,784	$2,605,626	$186,100,410
2027	$0	$0	$0	$5,938,720	$0	$5,938,720	$186,100,410	-$5,938,720	$180,161,690	$2,558,296	$182,719,986
2028	$0	$0	$0	$5,952,309	$0	$5,952,309	$182,719,986	-$5,952,309	$176,767,677	$2,510,101	$179,277,778
2029	$0	$0	$0	$5,952,309	$0	$5,952,309	$179,277,778	-$5,952,309	$173,325,469	$2,461,222	$175,786,691
2030	$0	$0	$0	$7,211,549	$0	$7,211,549	$175,786,691	-$7,211,549	$168,575,142	$2,393,767	$170,968,909
2031	$0	$0	$0	$7,211,549	$0	$7,211,549	$170,968,909	-$7,211,549	$163,757,360	$2,325,355	$166,082,714
2032	$0	$0	$0	$7,211,549	$0	$7,211,549	$166,082,714	-$7,211,549	$158,871,165	$2,255,971	$161,127,136
2033	$0	$0	$0	$7,211,549	$0	$7,211,549	$161,127,136	-$7,211,549	$153,915,587	$2,185,601	$156,101,188
2034	$0	$0	$0	$7,192,982	$0	$7,192,982	$156,101,188	-$7,192,982	$148,908,206	$2,114,497	$151,022,703
2035	$0	$0	$0	$7,211,549	$0	$7,211,549	$151,022,703	-$7,211,549	$143,811,154	$2,042,118	$145,853,272
2036	$0	$0	$0	$7,230,115	$0	$7,230,115	$145,853,272	-$7,230,115	$138,623,157	$1,968,449	$140,591,606
2037	$0	$0	$0	$7,211,549	$0	$7,211,549	$140,591,606	-$7,211,549	$133,380,057	$1,893,997	$135,274,054
2038	$0	$0	$0	$7,192,982	$0	$7,192,982	$135,274,054	-$7,192,982	$128,081,072	$1,818,751	$129,899,823
2039	$0	$0	$0	$7,211,549	$0	$7,211,549	$129,899,823	-$7,211,549	$122,688,274	$1,742,173	$124,430,448
2040	$0	$0	$0	$7,211,549	$0	$7,211,549	$124,430,448	-$7,211,549	$117,218,899	$1,664,508	$118,883,407
2041	$0	$0	$0	$7,211,549	$0	$7,211,549	$118,883,407	-$7,211,549	$111,671,858	$1,585,740	$113,257,598
2042	$0	$0	$0	$7,211,549	$0	$7,211,549	$113,257,598	-$7,211,549	$106,046,049	$1,505,854	$107,551,903
2043	$0	$0	$0	$7,211,549	$0	$7,211,549	$107,551,903	-$7,211,549	$100,340,354	$1,424,833	$101,765,187
2044	$0	$0	$0	$7,211,549	$0	$7,211,549	$101,765,187	-$7,211,549	$94,553,638	$1,342,662	$95,896,300
2045	$0	$0	$0	$7,192,982	$0	$7,192,982	$95,896,300	-$7,192,982	$88,703,318	$1,259,587	$89,962,905
2046	$0	$0	$0	$7,211,549	$0	$7,211,549	$89,962,905	-$7,211,549	$82,751,356	$1,175,069	$83,926,425
2047	$0	$0	$0	$7,211,549	$0	$7,211,549	$83,926,425	-$7,211,549	$76,714,876	$1,089,351	$77,804,227
2048	$0	$0	$0	$7,230,115	$0	$7,230,115	$77,804,227	-$7,230,115	$70,574,112	$1,002,152	$71,576,265
2049	$0	$0	$0	$7,192,982	$0	$7,192,982	$71,576,265	-$7,192,982	$64,383,283	$914,243	$65,297,525
2050	$0	$0	$0	$7,211,549	$0	$7,211,549	$65,297,525	-$7,211,549	$58,085,976	$824,821	$58,910,797
2051	$0	$0	$0	$7,192,982	$0	$7,192,982	$58,910,797	-$7,192,982	$51,717,815	$734,393	$52,452,208
2052	$0	$0	$0	$7,230,115	$0	$7,230,115	$52,452,208	-$7,230,115	$45,222,093	$642,154	$45,864,247
2053	$0	$0	$0	$7,211,549	$0	$7,211,549	$45,864,247	-$7,211,549	$38,652,698	$548,868	$39,201,566
2054	$0	$0	$0	$7,211,549	$0	$7,211,549	$39,201,566	-$7,211,549	$31,990,017	$454,258	$32,444,276
2055	$0	$0	$0	$7,192,982	$0	$7,192,982	$32,444,276	-$7,192,982	$25,251,294	$358,568	$25,609,862
2056	$0	$0	$0	$7,211,549	$0	$7,211,549	$25,609,862	-$7,211,549	$18,398,313	$261,256	$18,659,569
2057	$0	$0	$0	$7,211,549	$0	$7,211,549	$18,659,569	-$7,211,549	$11,448,020	$162,562	$11,610,582
2058	$0	$0	$0	$7,211,549	$0	$7,211,549	$11,610,582	-$7,211,549	$4,399,033	$62,466	$4,461,499
2059	$0	$0	$0	$7,211,549	$0	$7,211,549	$4,461,499	-$7,211,549	-$2,750,050	-$39,051	-$2,789,101
2060	$4,295,660	$3,701,294	$7,996,954	$7,211,549	$0	$15,208,503	-$2,789,101	-$15,208,503	-$17,997,604	$0	-$17,997,604
2061	$4,375,107	$3,701,294	$8,076,401	$7,211,549	$0	$15,287,950	-$17,997,604	-$15,287,950	-$33,285,554	$0	-$33,285,554
2062	$4,357,793	$3,701,294	$8,059,087	$7,192,982	$0	$15,252,069	-$33,285,554	-$15,252,069	-$48,537,623	$0	-$48,537,623
2063	$892,056	$3,701,294	$4,593,350	$2,440,549	$705,625	$7,739,524	-$48,537,623	-$7,739,524	-$56,277,147	$0	-$56,277,147

(1) LT, Added LT, SF and SR costs are from Holtec RAI response.
(2) Taxes computed at same rate as in Holtec LTA cash flow

120 Year SFM Cash Flow

Year	SFM Costs Without Repackaging (2)	Repackaging (1), (6), (7), (8), (9), (10)	SFM Costs With Repackaging
2018			
2019	$53,920		$53,920
2020	$84,905		$84,905
2021	$82,500		$82,500
2022	$3,332		$3,332
2023	$3,135		$3,135
2024	$3,225		$3,225
2025	$6,306		$6,306
2026	$5,952		$5,952
2027	$5,938		$5,938
2028	$5,952		$5,952
2029	$5,952		$5,952
2030	$7,212		$7,212
2031	$7,212		$7,212
2032	$7,212		$7,212
2033	$7,212		$7,212
2034	$7,193		$7,193
2035	$7,212		$7,212
2036	$7,230		$7,230
2037	$7,212		$7,212
2038	$7,193		$7,193
2039	$7,212		$7,212
2040	$7,212		$7,212
2041	$7,212		$7,212
2042	$7,212		$7,212
2043	$7,212		$7,212
2044	$7,212		$7,212
2045	$7,193		$7,193
2046	$7,212		$7,212
2047	$7,212		$7,212
2048	$7,230		$7,230
2049	$7,193		$7,193
2050	$7,212		$7,212
2051	$7,193		$7,193
2052	$7,230		$7,230
2053	$7,212		$7,212

Year	SFM Costs Without Repackaging (2)	Repackaging (1), (6), (7), (8), (9), (10)	SFM Costs With Repackaging
2054	$7,212		$7,212
2055	$7,193		$7,193
2056	$7,212		$7,212
2057	$7,212		$7,212
2058	$7,212		$7,212
2059	$7,212		$7,212
2060	$7,212		$7,212
2061	$7,212		$7,212
2062	$7,193		$7,193
2063	$7,210		$7,210
2064	$7,210		$7,210
2065	$7,210		$7,210
2066	$7,210		$7,210
2067	$7,210		$7,210
2068	$7,210		$7,210
2069	$7,210		$7,210
2070	$7,210		$7,210
2071	$7,210		$7,210
2072	$7,210		$7,210
2073	$7,210		$7,210
2074	$7,210		$7,210
2075	$7,210		$7,210
2076	$7,210		$7,210
2077	$7,210		$7,210
2078	$7,210		$7,210
2079	$7,210		$7,210
2080	$7,210		$7,210
2081	$7,210		$7,210
2082	$7,210		$7,210
2083	$7,210		$7,210
2084	$7,210		$7,210
2085	$7,210		$7,210
2086	$7,210		$7,210
2087	$7,210		$7,210
2088	$7,210		$7,210
2089	$7,210		$7,210
2090	$7,210		$7,210
2091	$7,210		$7,210
2092	$7,210		$7,210

Year	SFM Costs Without Repackaging (2)	Repackaging (1), (6), (7), (8), (9), (10)	SFM Costs With Repackaging	
2093	$7,210		$7,210	
2094	$7,210		$7,210	
2095	$7,210		$7,210	
2096	$7,210		$7,210	
2097	$7,210		$7,210	
2098	$7,210		$7,210	
2099	$7,210		$7,210	
2100	$7,210		$7,210	
2101	$7,210		$7,210	
2102	$7,210		$7,210	
2103	$7,210		$7,210	
2104	$7,210		$7,210	
2105	$7,210		$7,210	
2106	$7,210		$7,210	
2107	$7,210		$7,210	
2108	$7,210		$7,210	
2109	$7,210		$7,210	
2110	$7,210		$7,210	
2111	$7,210		$7,210	
2112	$7,210		$7,210	
2113	$7,210		$7,210	
2114	$7,210		$7,210	
2115	$7,210		$7,210	
2116	$7,210		$7,210	
2117	$7,210	$195,750	$202,960	(3)
2118	$7,210	$30,500	$37,710	(4)
2119	$7,210	$1,586	$8,796	(5)
2120	$7,210		$7,210	
2121	$7,210		$7,210	
2122	$7,210		$7,210	
2123	$7,210		$7,210	
2124	$7,210		$7,210	
2125	$7,210		$7,210	
2126	$7,210		$7,210	
2127	$7,210		$7,210	
2128	$7,210		$7,210	
2129	$7,210		$7,210	
2130	$7,210		$7,210	
2131	$7,210		$7,210	

Year	SFM Costs Without Repackaging (2)	Repackaging (1), (6), (7), (8), (9), (10)	SFM Costs With Repackaging
2132	$7,210		$7,210
2133	$7,210		$7,210
2134	$7,210		$7,210
2135	$7,210		$7,210
2136	$7,210		$7,210
2137	$7,210		$7,210
2138	$2,441		$2,441
Total	**$1,042,225**	**$227,836**	**$1,270,061**

Notes:

(1) While not a requirement, NRC at present assumes fuel would have to be repackaged every 100 year. The repackaging costs estimated include four basic elements: Construction of Dry Transfer Facility, New Spent Fuel Canisters, Disposal of Old Canisters and Labor for Repackaging.

(2) For years 2063 through 2136, the base storage cost is equal to the average cost in Holtec's cash flow for years 2029 through 2062.

(3) As a conservative measure, the cost of the dry fuel transfer facility is all presented in year 99 (2117). In fact it would be spread over some number of years leading to that date. In the same conservative manner, all costs for new canisters have been included in year 99.

(4) All reloading labor estimated is included in year 100 (2118).

(5) All costs for disposal of old canisters is included in year 101 (2119).

(6) Cost for construction is $150 million which is the low end of the range estimate by GAO. GAO maximum estimate is $450 million.

(7) Spent fuel repackaging labor is estimated at $500 thousand per canister. This is based on starting from cost of over $1 million per canister that have been reported for just loading. In this case, the activities would include unloading as well as loading. However, this may be more than offset by the process being dry which eliminates substantial costs in current loading costs for draining and drying the canister after loading. Additionally, the reported costs today are based on relative small number of canisters being loaded in each campaign. For repackaging, the repakaging would likely be larger campaigns and perhaps one campaign for all fuel.

(8) Canister costs are estimated as $750 thousand per cask which is a conservative low estimate based on current reported costs.

(9) Cost for disposal of old canisters assumes the canisters would be cut up to reduce the volume such that the packaged waste would have a density of about 150 lbs per cubic foot. Combining this with a conservative estimate of disposal cost of $100 per cubic foot and canister weight of about 39,000 lbs, the total disposal cost would be about 26,000 per canister. This inherently assumes the cutting of the canisters is done at no cost.

(10) Total of 61 spent fuel storage casks based on Holtec PSDAR.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE COMMISSION

In the Matter of	)	
	)	
ENTERGY NUCLEAR OPERATIONS, INC.,	)	
ENTERGY NUCLEAR GENERATION	)	
COMPANY, AND HOLTEC	)	
DECOMMISSIONING INTERNATIONAL,	)	Docket Nos. 50-293 & 72-1044
LLC; CONSIDERATION OF APPROVAL OF	)	
TRANSFER OF LICENSE AND	)	
CONFORMING AMENDMENT	)	
	)	
(Pilgrim Nuclear Power Station)	)	

DECLARATION OF JOSEPH DORFLER

I, Joseph Dorfler, declare and state as follows:

1. My name is Joseph Dorfler. I am an Assistant Attorney General in the Energy and Telecommunications Division of the Office of Massachusetts Attorney General Maura Healey. I am one of the attorneys representing the Commonwealth of Massachusetts in this case. I am over 18 years of age and am fully competent in all respects to make this Declaration. I have personal knowledge of the facts stated herein, and each of them is true and correct.

2. I submit this declaration in support of the Application of the Commonwealth of Massachusetts for a Stay of the Effectiveness of the Nuclear Regulatory Commission Staff's Actions Approving the License Transfer Application and Request for an Exemption to Use the Decommissioning Trust Fund for Non-Decommissioning Purposes.

3. Attached to this declaration as **Exhibit 1** is a true and accurate copy of the Order Approving the Transfer of Facility Operating License and Materials License for Pilgrim Nuclear Generation Company, and Approving Conforming Amendment with attached Order, Conforming Amendments, and Safety Evaluation, Docket No. 50-293, by the United States

Nuclear Regulatory Commission, ADAMS Accession No. ML011910099. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML0119/ML011910099.pdf, on August 30, 2019.

4. Attached to this declaration as **Exhibit 2** is a true and accurate copy of a Report to the Subcommittee on Energy and Water Development, Committee on Appropriations, House of Representatives, dated September 2008, by the United States Government Accountability Office titled *Action needed to Improve Accountability and Management of DOE's Major Cleanup Projects*, GAO-08-1081. I obtained a copy of the document from the Government Accountability Office website, which is accessible at https://www.gao.gov/new.items/d081081.pdf, on August 29, 2019.

5. Attached to this declaration as **Exhibit 3** is a true and accurate copy of a Backgrounder on Decommissioning Nuclear Power Plants by the United States Nuclear Regulatory Commission, last updated on August 15, 2018. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/decommissioning.html, on August 29, 2019.

6. Attached to this declaration as **Exhibit 4** is a true and accurate copy of a Policy Issue (Information) memorandum, dated October 2, 2013, from Eric J. Leeds, Director, Office of Nuclear Reactor Regulation to the Commissioners of United States Nuclear Regulatory Commission, titled *Summary Findings Resulting from the Staff Review of the 2013 Decommissioning Funding Status Reports for Operating Power Reactor Licensees*, SECY-13-0105. I obtained a copy of the document from the Nuclear Regulatory Commission's website,

which is accessible at https://www.nrc.gov/reading-rm/doc-collections/commission/secys/2013/2013-0105scy.pdf, on August 29, 2019.

7. Attached to this declaration as **Exhibit 5** is a true and accurate copy of the Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities, Supplement 1, Volume 1, published November 2002, by the United States Nuclear Regulatory Commission, NUREG-0586, ADAMS Accession Nos. ML023470304 and ML023470323. I obtained a copy of the document from Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr0586/s1/v1/, on August 29, 2019.

8. Attached to this declaration as **Exhibit 6** is a true and accurate copy of a 2014 Tritium Update Summary for Pilgrim Nuclear Power Station by the Massachusetts Department of Public Health titled *Pilgrim Nuclear Power Station (PNPS): Tritium in Groundwater Monitoring Wells*, updated as of February 7, 2014. I obtained a copy of the document from the Commonwealth of Massachusetts' website, which is accessible at https://www.mass.gov/files/documents/2016/07/vv/pnps-update-02-07-14.pdf, on August 29, 2019.

9. Attached to this declaration as **Exhibit 7** is a true and accurate copy of a News Release by Southern California Edison, titled *SCE to Brief Path Forward for Fuel Transfer Operations Restart*, dated November 28, 2018. I obtained a copy of the document from the Southern California Edison's website, which is accessible at https://www.songscommunity.com/news/releases/sce-to-brief-path-forward-for-fuel-transfer-operations-restart, on August 29, 2019.

10. Attached to this declaration as **Exhibit 8** is a true and accurate copy of a News Release by Southern California Edison, titled *Southern California Edison Statement on Spent Nuclear Fuel Canister*, dated August 10, 2018. I obtained a copy of the document from Southern California Edison's website, which is accessible at https://www.songscommunity.com/news/releases/southern-california-edison-statement-on-spent-nuclear-fuel-canister, on August 29, 2019.

11. Attached to this declaration as **Exhibit 9** is (selected sections of) a true and accurate copy of the Fourth National Climate Assessment, Volume II: *Impacts, Risks, and Adaptation in the United States*, by the United States Global Change Research Program, dated 2018. I obtained a copy of the document from the Global Change Research Program's website, which is accessible at https://nca2018.globalchange.gov/downloads/NCA4_2018_FullReport.pdf, on August 29, 2019.

12. Attached to this declaration as **Exhibit 10** is a true and accurate copy of a News Article by Allison Lampert, titled *Canada's SNC Lavalin Eyes Ways to Protect Business Amid Political Crisis*, dated March 22, 2019. I obtained a copy of the document from Reuters' website, which is accessible at https://www.reuters.com/article/us-canada-politics-snc-lavalin/canadas-snc-lavalin-eyes-ways-to-protect-business-amid-political-crisis-idUSKCN1R32TN, on August 29, 2019.

13. Attached to this declaration as **Exhibit 11** is a true and accurate copy of a News Article by Sandrine Rastello and Laura Millan Lombrana, titled *SNC-Lavalin 'Appalled' and 'Surprised' as Chilean Miner Codelco Cancels $260-Million Contract*, dated March 26, 2019. I obtained a copy of the document from Bloomberg News' website, which is accessible at

https://business.financialpost.com/commodities/mining/snc-dealt-another-blow-with-copper-mine-project-cancellation, on August 29, 2019.

14. Attached to this declaration as **Exhibit 12** is a true and accurate copy of a Report to Congressional Requestors, dated November 2009, by the United States Government Accountability Office, titled *Nuclear Waste Management: Key Attributes, Challenges, and Costs for the Yucca Mountain Repository and Two Potential Alternatives*. I obtained a copy of the document from the Government Accountability Office's website, which is accessible at https://www.gao.gov/assets/300/298028.pdf, on August 29, 2019.

15. Attached to this declaration as **Exhibit 13** is a true and accurate copy of a News Article by Christinne Muschi of Reuters, updated May 8, 2019, titled *SNC-Lavalin Executives Ponder Company Break-Up at Private Shareholder Luncheon*. I obtained a copy of the document from the Financial Post's website, which is accessible at https://business.financialpost.com/news/fp-street/snc-lavalin-execs-ponder-company-break-up-at-private-shareholder-luncheon, on August 29, 2019.

16. Attached to this declaration as **Exhibit 14** is a true and accurate copy of an Email from Amy Snyder, Senior Project Manager, Reactor Decommissioning Branch, United State Nuclear Regulatory Commission to Veena Gubbi, Paul Schwartz, and Paul Orlando, from the State of New Jersey, titled "For Your Comments – State of New Jersey – Oyster Creek – Conforming Amendment Associated with the Oyster Creek Generating Station License Transfer Application," dated May 16, 2019. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1913/ML19137A036.pdf, on August 30, 2019.

17. Attached to this declaration as **Exhibit 15** is a true and accurate copy of *Safety Evaluation by the Office of Nuclear Reactor Regulation and Office of Nuclear Material Safety and Safeguards, Related Request for Direct Transfer of Control of Renewed Facility Operating License No. DPR-16 and the General License for the Independent Spent Fuel Storage Installation from Exelon Generation Company, LLC to Oyster Creek Environmental Protection, LLC and Holtec Decommissioning International, LLC* (Oyster Creek Nuclear Generating Station), dated June 20, 2019, from Docket Number 50-219 & 72-15 ADAMS Accession No. ML19095A457. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1909/ML19095A457.pdf, on August 29, 2019.

18. Attached to this declaration as **Exhibit 16** is a true and accurate copy of the Entergy Nuclear Generation Company and Entergy Nuclear Operations, Inc (Pilgrim Nuclear Power Station), Docket No. 50-293, Renewed Facility Operating License No. DPR-35, dated May 29, 2012, from the United States Nuclear Regulatory Commission, ADAMS Accession No. ML052720275. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML0527/ML052720275.pdf, on August 30, 2019.

19. Attached to this declaration as **Exhibit 17** is a true and accurate copy of an Audit Report by the Office of the Inspector General, United States Nuclear Regulatory Commission, titled *Audit of NRC's Transition Process for Decommissioning Power Reactors*, OIG-19-A-16, dated, August 23, 2019. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1923/ML19235A246.pdf, on August 30, 2019.

20. Attached to this declaration as **Exhibit 18** is a true and accurate copy of a United States Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation Office Instruction titled “Procedures for Handling License Transfers,” LIC-107, Revision 2, effective date June 5, 2017. I obtained a copy of the document from the Nuclear Regulatory Commission’s website, which is accessible at https://www.nrc.gov/docs/ML1703/ML17031A006.pdf, on August 30, 2019.

21. Attached to this declaration as **Exhibit 19** is a true and accurate copy of a Request for Additional Information from the United States Nuclear Regulatory Commission Staff to Entergy Nuclear Operations, Inc, RAI-IRAB-1, Docket Nos. 50-293 and 72-1044, dated March 21, 2019, ADAMS Accession No. ML19086A349. I obtained a copy of the document from the Nuclear Regulatory Commission’s website, which is accessible at https://www.nrc.gov/docs/ML1908/ML19086A349.pdf, on August 30, 2019.

22. Attached to this declaration as **Exhibit 20** is a true and accurate copy of a Response by Holtec Decommissioning International to a Request for Additional Information from the United States Nuclear Regulatory Commission Staff, Docket Nos. 50-293 and 72-1044, dated April 17, 2019, ADAMS Accession No. ML19109A177. I obtained a copy of the document from the Nuclear Regulatory Commission’s website, which is accessible at https://www.nrc.gov/docs/ML1910/ML19109A177.pdf, on September 3, 2019.

23. Attached to this declaration as **Exhibit 21** is a true and accurate copy of Request for Additional Information from the United States Nuclear Regulatory Commission Staff to Entergy Nuclear Operations, Inc, EPID: L-2018-LLA-0268, Docket No. 50-293, dated June 3, 2019, ADAMS Accession No. ML19154A524. I obtained a copy of the document from the Nuclear

Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1915/ML19154A524.pdf, on August 30, 2019.

24. Attached to this declaration as **Exhibit 22** is a true and accurate (public version) copy of a Response by Entergy Nuclear Operations, Inc. to a Request for Additional Information from the United States Nuclear Regulatory Commission Staff, Docket Nos. 50-293 and 72-1044, dated July 16, 2019, ADAMS Accession No. ML19197A114. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1919/ML19197A114.pdf, on September 3, 2019.

25. Attached to this declaration as **Exhibit 23** is a true and accurate copy of Request for Additional Information from the United States Nuclear Regulatory Commission Staff to Entergy Nuclear Operations, Inc, RAI-PFPB-1, Docket No. 50-293 and 72-1044, dated July 26, 2019, ADAMS Accession No. ML19207B366. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1920/ML19207B366.pdf, on August 30, 2019.

26. Attached to this declaration as **Exhibit 24** is a true and accurate copy of a Response by Holtec Decommissioning International to a Request for Additional Information from the United States Nuclear Regulatory Commission Staff, Docket Nos. 50-293 and 72-1044, dated July 29, 2019, ADAMS Accession No. ML19210E470. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1921/ML19210E470.pdf, on August 30, 2019.

27. Attached to this declaration as **Exhibit 25** is a true and accurate copy of Enclosure 5 to a Policy Issue (Notation Vote) memorandum, SECY-11-0133, dated September 28, 2011, from R.W. Borchardt, Executive Director of Operations, to the Commissioners of the United

States Nuclear Regulatory Commission, titled *Questions and Answers on Decommissioning Financial Assurance*, ADAMS Accession No. ML111950031. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1119/ML111950031.pdf, on September 3, 2019.

28. Attached to this declaration as **Exhibit 26** is a true and accurate copy of a Policy Issue (Information) memorandum, SECY-10-0084, dated June 25, 2010, from Eric J. Leeds, Director, office of Nuclear Reactor Regulation to the Commissioners of the United States Nuclear Regulatory Commission, titled *Explanation of Changes to Revision 2 to Regulatory Guide 1.159 "Assuring the Availability of Funds for Decommissioning Nuclear Reactors."* I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/reading-rm/doc-collections/commission/secys/2010/secy2010-0084/2010-0084scy.pdf, on September 3, 2019.

29. Attached to this declaration as **Exhibit 27** is a true and accurate copy of a Commission Voting Record to Decision Item: SECY-10-0084, titled *Explanation of Changes to Revision 2 to Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors"* dated October 25, 2010. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/reading-rm/doc-collections/commission/cvr/2010/2010-0084vtr.pdf, on September 3, 2019.

30. Attached to this declaration as **Exhibit 28** is a true and accurate copy of a Letter from the United States Nuclear Regulatory Commission to Southern California Edison Company, dated December 19, 2018, with the subject *San Onofre Nuclear Generating Station - NRC Special Inspection Report 050-00206/2018-005, 050-00361/2018-005, 050-00362/2018-005, 072-00041/2018-001 and Notice of Violation*, ADAMS Accession No. ML18341A172. I

obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1834/ML18341A172.pdf, on September 3, 2019.

31. Attached to this declaration as **Exhibit 29** is (selected sections of) a true and accurate copy of the Environmental Report on the HI-STORE CIS Facility by Holtec International, Docket No. 72-1051, dated May 2019, ADAMS Accession No. ML19163A146. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1916/ML19163A146.pdf, on September 3, 2019.

32. Attached to this declaration as **Exhibit 30** is a true and accurate copy of *Safety Evaluation by the Office of Nuclear Reactor Regulation and Office of Nuclear Material Safety and Safeguards, Related to Request for Direct and Indirect Transfers of Control of Renewed Facility Operating License No. DPR-28 and the General License for the Independent Spent Fuel Storage Installation from Entergy Nuclear Operations, Inc. and Entergy Nuclear Vermont Yankee, LLC to Northstar Vermont Yankee, LLC and Northstar Nuclear Decommissioning Company, LLC* (Vermont Yankee Nuclear Power Station), dated October 11, 2018, from Docket Number 50-271 & 72-59, ADAMS Accession No. ML18242A639. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1824/ML18242A639.pdf, on September 3, 2019.

33. Attached to this declaration as **Exhibit 31** is a true and accurate copy of a Report to Congress on the Demonstration of the Interim Storage of Spent Nuclear Fuel from Decommissioned Nuclear Power Reactor Sites by the United States Department of Energy, dated December 2008, DOE/RW-0596. I obtained a copy of the document from the Department of Energy's website, which is accessible at

https://www.energy.gov/sites/prod/files/edg/media/ES_Interim_Storage_Report_120108.pdf, on September 3, 2019.

34. Attached to this declaration as **Exhibit 32** is a true and accurate copy of Comments of the Institute for Energy and Environmental Research on the U.S. Nuclear Regulatory Commission's Proposed Waste Confidence Rule Update and Proposed Rule Regarding Environmental Impacts of Temporary Spent Fuel Storage, by Arjun Makhijani, President, Institute for Energy and Environmental Research, dated February 6, 2009. I obtained a copy of the document from the Institute for Energy and Environmental Research's website, which is accessible at https://ieer.org/wp/wp-content/uploads/2012/06/WasteConfidenceComments2009.pdf, on September 3, 2019.

35. Attached to this declaration as **Exhibit 33** is a true and accurate copy of an article titled *The Growing Problem of Stranded Used Nuclear Fuel*, by William M. Alley and Rosemarie Alley, 48 Envtl. Science & Tech. 2091, published January 17, 2014. I obtained a copy of the document from the ACS Publications website, which is accessible at https://pubs.acs.org/doi/pdf/10.1021/es405114h?rand=139s5mpb, on September 3, 2019.

36. Attached to this declaration as **Exhibit 34** is a true and accurate copy of the Standard Review Plan for Decommissioning Cost Estimates for Nuclear Power Reactors, Final Report, published October 2004, by the United States Nuclear Regulatory Commission, NUREG-1713, ADAMS Accession Nos. ML043510113. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML0435/ML043510113.pdf, on September 3, 2019.

37. Attached to this declaration as **Exhibit 35** is a true and accurate copy of Regulatory Guide 1.202, titled *Standard Format and Content of Decommissioning Cost Estimates for*

Nuclear Power Reactors, by the Office of Nuclear Regulatory Research, United States Nuclear Regulatory Commission, dated February 2005. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML0502/ML050230008.pdf, on September 3, 2019.

38. Attached to this declaration as **Exhibit 36** is a true and accurate copy of the Reply of the Commonwealth of Massachusetts and the States of Connecticut and New Hampshire to NRC Staff's and Entergy's Answers to the Petition of the State of Vermont, the Vermont Yankee Nuclear Power Corporation, and Green Mountain Power Corporation for Review of Entergy Nuclear Operations, Inc.'s Planned Use of the Vermont Yankee Nuclear Decommissioning Trust Fund, submitted in *In the Matter of Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc.* (Vermont Yankee Nuclear Power Station), Docket No. 50-271, dated December 17, 2015, ADAMS Accession No. 15351A531. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1535/ML15351A531.pdf on September 3, 2019.

39. Attached to this declaration as **Exhibit 37** is a true and accurate copy of the Order Approving the Transfer of License and Conforming Amendment, dated October 11, 2018, in *In the Matter of Entergy Nuclear Vermont Yankee, LLC, Entergy Nuclear Operations, Inc.* (Vermont Yankee Nuclear Power Station), Docket No. 50-271 and 72-59, License No. DPR-28, ADAMS Accession No. ML18248A096. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1824/ML18248A096.pdf, on September 3, 2019.

40. Attached to this declaration as **Exhibit 38** is a true and accurate copy of a Letter from Stephanie Garcia Richard, Commissioner, State of New Mexico, Commissioner of Public Lands,

to Krishna P. Singh, President and CEO, Holtec International, dated June 19, 2019. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1918/ML19183A429.pdf, on September 3, 2019.

41. Attached to this declaration as **Exhibit 39** is a (selected sections of) true and accurate copy of Electric Power Research Institute Technical Report 1013511, titled *Connecticut Yankee Decommissioning Experience Report, Detailed Experiences 1996-2006,* dated November 2006. I obtained a copy of the document from the Electric Power Research Institute's website, which is accessible at https://www.epri.com/#/pages/product/1013511/?lang=en-US, on September 3, 2019.

42. Attached to this declaration as **Exhibit 40** is a true and accurate copy of Electric Power Research Institute Report, prepared by New Horizon Scientific, LLC, titled *Maine Yankee Decommissioning Experience Report, Detailed Experiences 1997-2004,* submitted to the United States Nuclear Regulatory Commission on March 28, 2012, ADAMS Accession No. ML12338A389. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1233/ML12338A389.pdf, on September 3, 2019.

43. Attached to this declaration as **Exhibit 41** is a true and accurate copy of the *Strategy for the Management and Disposal of Used Nuclear Fuel and High-level Radioactive Waste* by the United States Department of Energy, dated January 2013. I obtained a copy of the documents from the Department of Energy's website, which is accessible at https://www.energy.gov/sites/prod/files/2013%201-15%20Nuclear_Waste_Report.pdf, on September 3, 2019.

44. Attached to this declaration as **Exhibit 42** is a true and accurate copy of Office of the Inspector General, Tennessee Valley Authority, Semiannual Report 18, (April 1, 2015 to September 30, 2015). I obtained a copy of the document from the Office of the Inspector General, Tennessee Valley Authority's website, which is accessible at https://oig.tva.gov/reports/semi59.pdf, on September 3, 2019.

45. Attached to this declaration as **Exhibit 43** is a true and accurate copy of Officer of the Inspector General, Tennessee Valley Authority, Semiannual Report 8, (October 1, 2010 to March 31, 2011). I obtained a copy of the document from Office of the Inspector General, Tennessee Valley Authority's website, which is accessible at https://oig.tva.gov/reports/semi50.pdf, on September 3, 2019.

46. Attached to this declaration as **Exhibit 44** is a true and accurate (public version) copy of Office of Inspector General, Tennessee Valley Authority, Report of Administrative Inquiry 1 (March 23, 2010). I obtained a copy of the document from Politico's website, which is accessible at https://www.politico.com/states/f/?id=0000016b-d7ca-d6eb-a96f-fffebfa70001, on September 3, 2019.

47. Attached to this declaration as **Exhibit 45** is a true and accurate copy of a News Article by Andrew Seidman and Catherine Dunn, *Holtec Funneled $50,000 to Federal Employee in Bid to Win Contract, Inspector General Report Says*, The Philadelphia Inquirer, July 9, 2019. I obtained a copy of the document from The Philadelphia Inquirer's website, which is accessible at https://www.inquirer.com/business/holtec-tennessee-valley-authority-nj-tax-credit-investigation-20190709.html, on September 3, 2019.

48. Attached to this declaration as **Exhibit 46** is a true and accurate copy of a News Article by Nancy Solomon and Jeff Pillets, *Holtec's $260 Million Tax Break Frozen by NJ EDA*,

WNYC News, June 4, 2019. I obtained a copy of the document from WNYC News's website, which is accessible at https://www.wnyc.org/story/holtecs-260-million-tax-break-frozen-eda/, on September 3, 2019.

49. Attached to this declaration as **Exhibit 47** is a true and accurate copy of a News Article by Ryan Hutchins, *Task Force Uncovers Bombshell Report on Holtec*, Politico, July 10, 2019. I obtained a copy of the document from Politico's website, which is accessible at https://www.politico.com/newsletters/new-jersey-playbook/2019/07/10/task-force-uncovers-bombshell-report-on-holtec-454824, on September 3, 2019.

50. Attached to this declaration as **Exhibit 48** is a true and accurate copy of Notice of Violation to Holtec International from the United States Nuclear Regulatory Commission, OE EA 18-151, dated April 24, 2019, ADAMS Accession No. 19072A128. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1907/ML19072A128.pdf, on September 3, 2019.

51. Attached to this declaration as **Exhibit 49** is a true and accurate copy of a Blog Post by Richard L. Cassin, *Former SNC-Lavalin Chief Pleads Guilty in Bribery Case*, The FPCA Blog, dated February 4, 2019. I obtained a copy of the document from The FPCA Blog website, which is accessible at https://www.fcpablog.com/blog/2019/2/4/former-snc-lavalin-chief-pleads-guilty-in-bribery-case.html, on September 3, 2019.

52. Attached to this declaration as **Exhibit 50** is a true and accurate copy of a News Article by Shanti S. Nair, *SNC-Lavalin Cuts Dividend, Posts Wider-Than-Expected Loss as Costs Run High*, Reuters, dated August 1, 2019. I obtained a copy of the document from Reuters' website, which is accessible at https://www.reuters.com/article/us-snc-lavalin-

results/snc-lavalin-cuts-dividend-posts-wider-than-expected-loss-as-costs-run-high-idUSKCN1UR4FQ, on September 3, 2019.

53. Attached to this declaration as **Exhibit 51** is a true and accurate copy of the Objection of the Commonwealth of Massachusetts to Proposed Staff Action on License Transfer Application and Exemption Request, Pilgrim Nuclear Power Station, NRC Docket Nos. 50-293 and 72-1044, dated August 21, 2019, ADAMS Accession No. ML19233A278. I obtained a copy of the document from the Nuclear Regulatory Commission's website, which is accessible at https://www.nrc.gov/docs/ML1923/ML19233A278.pdf, on September 3, 2019.

54. I, Joseph Dorfler, have read the above statement consisting of 16 pages, and I certify under penalty of perjury that the foregoing is true and correct. Executed on September 3, 2019.

Signed (electronically) by
Joseph Dorfler
Assistant Attorney General
Energy and Environment Bureau
Attorney General's Office

Mr. Theodore A. Sullivan
Vice President Nuclear an tation Director
Boston Edison Company
Pilgrim Nuclear Power Station
RFD #1 Rocky Hill Road
Plymouth, MA 02360

Jerry W. Yelverton
President and Chief ecutive Officer
Entergy Nuclear Generation Company
1340 Echelon Parkway
Jackson, LA 39213

April 29, 1999

SUBJECT: ORDER APPROVING THE TRANSFER OF FACILITY OPERATING LICENSE AND MATERIALS LICENSE FOR PILGRIM NUCLEAR POWER STATION, FROM BOSTON EDISON COMPANY TO ENTERGY NUCLEAR GENERATION COMPANY, AND APPROVING CONFORMING AMENDMENTS (TAC NO. MA4447)

Dear Mr. Sullivan and Mr. Yelverton:

The enclosed Order is in response to the application dated December 21, 1998, as supplemented on January 28, February 18, April 2, April 15, and April 16, 1999, requesting approval of the transfer of Operating License DPR-35 and NRC Materials License No. 20-07626-04 for the Pilgrim Nuclear Power Station (Pilgrim) from Boston Edison Company (Boston Edison) to Entergy Nuclear Generation Company (Entergy Nuclear), and approval of conforming amendments. The enclosed Order provides consent to the proposed transfer, pursuant to Sections 30.34, 40.41, 50.80, and 70.32, of Title 10 of the Code of Federal Regulations, subject to the conditions set forth therein. The Order also approves conforming license amendments pursuant to 10 CFR 30.38, 40.44, 50.90, and 70.34, to be issued and made effective at the time the transfer is completed.

The Order has been forwarded to the Office of the Federal Register for publication.

Sincerely,

ORIGINAL SIGNED BY:
Alan B. Wang, Project Manager, Section 2
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-293
Enclosures: 1. Order
2. Conforming Amendments
3. Safety Evaluation (Non-Proprietary)
4. Safety Evaluation (Proprietary)
cc w/encls: See next page

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DF03

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 29, 1999

Mr. Theodore A. Sullivan
Vice President Nuclear and Station Director
Boston Edison Company
Pilgrim Nuclear Power Station
RFD #1 Rocky Hill Road
Plymouth, MA 02360

Jerry W. Yelverton
President and Chief Executive Officer
Entergy Nuclear Generation Company
1340 Echelon Parkway
Jackson, LA 39213

SUBJECT: ORDER APPROVING THE TRANSFER OF FACILITY OPERATING LICENSE AND MATERIALS LICENSE FOR PILGRIM NUCLEAR POWER STATION, FROM BOSTON EDISON COMPANY TO ENTERGY NUCLEAR GENERATION COMPANY, AND APPROVING CONFORMING AMENDMENTS (TAC NO. MA4447)

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The Order has been forwarded to the Office of the Federal Register for publication.

Sincerely,

Alan Wang

Alan B. Wang, Project Manager, Section 2
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-293

Enclosures:
1. Order
2. Conforming Amendments
3. Safety Evaluation (Non-Proprietary)
4. Safety Evaluation (Proprietary)

cc w/encls: See next page

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cc w/Enclosures 1, 2, & 3:

Pilgrim Nuclear Power Station

cc:
Mr. Ron Ledgett
Executive Vice President
800 Boyleston Street
Boston, MA 02199

Resident Inspector
U. S. Nuclear Regulatory Commission
Pilgrim Nuclear Power Station
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Plymouth, MA 02360

Chairman, Board of Selectmen
11 Lincoln Street
Plymouth, MA 02360

Chairman, Duxbury Board of Selectmen
Town Hall
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Duxbury, MA 02332

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Massachusetts Department of
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Boston, MA 02108

Office of the Attorney General
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Boston, MA 02108

Mr. Robert M. Hallisey, Director
Radiation Control Program
Massachusetts Department of
Public Health
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Boston, MA 02130

Regional Administrator, Region I
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Acting Licensing Division Manager
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Mr. Jack Alexander
Manager, Reg. Relations and Quality
Assurance
Pilgrim Nuclear Power Station
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Mr. David F. Tarantino
Nuclear Information Manager
Pilgrim Nuclear Power Station
RFD #1, Rocky Hill Road
Plymouth, MA 02360

Ms. Kathleen M. O'Toole
Secretary of Public Safety
Executive Office of Public Safety
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Boston, MA 02108

Mr. Peter LaPorte, Director
Attn: James Muckerheide
Massachusetts Emergency Management
Agency
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Framingham, MA 01701-0317

Chairman, Citizens Urging
Responsible Energy
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Duxbury, MA 02331

Citizens at Risk
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Plymouth, MA 02361

W.S. Stowe, Esquire
Boston Edison Company
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Boston, MA 02199

Chairman
Nuclear Matters Committee
Town Hall
11 Lincoln Street
Plymouth, MA 02360

Mr. William D. Meinert
Nuclear Engineer
Massachusetts Municipal Wholesale
Electric Company
P.O. Box 426
Ludlow, MA 01056-0426

Ms. Mary Lampert, Director
Massachusetts Citizens for Safe Energy
148 Washington Street
Duxbury, MA 02332

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April 29, 1999

MEMORANDUM TO: Rules and Directives Branch
Division of Administrative Services
Office of Administration

FROM: Office of Nuclear Reactor Regulation

SUBJECT: **BOSTON EDISON COMPANY - PILGRIM NUCLEAR POWER STATION**

One signed original of the *Federal Register* Notice identified below is attached for your transmittal to the Office of the Federal Register for publication. Additional conformed copies (**FIVE**) of the Notice are enclosed for your use.

- [ ] Notice of Receipt of Application for Construction Permit(s) and Operating License(s).
- [ ] Notice of Receipt of Partial Application for Construction Permit(s) and Facility License(s): Time for submission of Views on Antitrust matters.
- [ ] Notice of Consideration of Issuance of Amendment to Facility Operating License. (Call with 30-day insert date).
- [ ] Notice of Receipt of Application for Facility License(s); Notice of Availability of Applicant's Environmental Report; and Notice of Consideration of Issuance of Facility License(s) and Notice of Opportunity for Hearing.
- [ ] Notice of Availability of NRC Draft/Final Environmental Statement.
- [ ] Notice of Limited Work Authorization.
- [ ] Notice of Availability of Safety Evaluation Report.
- [ ] Notice of Issuance of Construction Permit(s).
- [ ] Notice of Issuance of Facility Operating License(s) or Amendment(s).
- [X] Order.
- [ ] Exemption.
- [ ] Notice of Granting Exemption.
- [ ] Environmental Assessment.
- [ ] Notice of Preparation of Environmental Assessment.
- [ ] Receipt of Petition for Director's Decision Under 10 CFR 2.206.
- [ ] Issuance of Final Director's Decision Under 10 CFR 2.206.
- [ ] Other: ______________________________

DOCKET NO. **50-293**

030008

Attachment(s): As stated

Contact: **A. Wang**
Telephone: **415-1445**

DOCUMENT NAME: ORD4447.WPD

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
BOSTON EDISON COMPANY	)	Docket No. 50-293
	)	
(Pilgrim Nuclear Power Station, Unit No. 1)	)	

ORDER APPROVING TRANSFER OF LICENSES AND CONFORMING AMENDMENTS

I.

Boston Edison Company (Boston Edison) is owner of the Pilgrim Nuclear Power Station (Pilgrim), and is authorized to possess, use, and operate the facility as reflected in Operating License No. DPR-35. Boston Edison also is the holder of Materials License No. 20-07626-04, which authorizes Boston Edison to possess, use, and transport certain materials in the form of contamination on reactor components. The Atomic Energy Commission issued Operating License No. DPR-35 on September 15, 1972, pursuant to Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR Part 50). Materials License No. 20-07626-04 was issued on March 21, 1997, pursuant to 10 CFR Parts 30, 40, and 70. The facility is located in Plymouth County, on the southeast coast of the State of Massachusetts.

II.

Under cover of a letter dated December 21, 1998, Boston Edison and Entergy Nuclear Generation Company (Entergy Nuclear) jointly submitted an application requesting approval of the proposed transfer of Operating License No. DPR-35 and Materials License No. 20-07626-04 from Boston Edison to Entergy Nuclear. The application also requested approval of conforming amendments to reflect the transfer. The application was supplemented by

submittals dated January 28, February 18, April 2, April 15, and April 16, 1999. The initial application and the supplements are hereinafter collectively referred to as "the application" unless otherwise indicated.

Boston Edison is a wholly-owned subsidiary of BEC Energy, a Massachusetts business trust. Entergy Nuclear, a Delaware corporation, is an indirect wholly owned subsidiary of Entergy Corporation. According to the application, Boston Edison has agreed to sell its ownership interest in Pilgrim to Entergy Nuclear, subject to obtaining all necessary regulatory approvals. After the completion of the proposed sale and transfer, Entergy Nuclear would be the sole owner and operator of Pilgrim. The conforming amendments, which would be issued pursuant to 10 CFR 30.38, 40.44, 50.90, and 70.34, would remove references to Boston Edison from the Operating License and Materials License, and replace them with references to Entergy Nuclear, as well as make miscellaneous changes to the Operating License, administrative in nature, to reflect the transfer.

Notice of the initial application and an opportunity for a hearing was published in the *Federal Register* on January 26, 1999 (64 FR 3984) and supplemented on February 5, 1999 (64 FR 5841). Pursuant to such notice, the Attorney General of the Commonwealth of Massachusetts and Local Unions 369 and 387 filed hearing requests. By letter dated April 7, 1999, Local Unions 369 and 387 formally withdrew their request. Similarly, on April 16, 1999, the Attorney General of the Commonwealth of Massachusetts withdrew his request. The Commission, in light of the withdrawals, terminated the pending proceeding on April 26, 1999, Boston Edison Co. (Pilgrim Nuclear Power Station), CLI-99-17, 49 NRC _____, slip op. (April 26, 1999). Certain municipalities which purchase power from Pilgrim filed written comments, and Citizens Urging Responsible Energy filed written comments and requested a

public hearing. The written comments have been considered by the staff in connection with the issuance of this Order.

Under 10 CFR 50.80, no license for a production or utilization facility, or any right thereunder, shall be transferred, directly or indirectly, through transfer of control of the license, unless the Commission shall give its consent in writing. Under 10 CFR 30.34, 40.41, and 70.32, no byproduct, source, or special nuclear material license shall be transferred in violation of the provisions of the Atomic Energy Act of 1954, as amended, which require, inter alia, Commission consent. Upon review of the information in the application by Boston Edison and Entergy Nuclear, and other information before the Commission, and relying upon the representations and agreements contained in the application, the NRC staff has determined that Entergy Nuclear is qualified to hold the licenses, and that the transfer of the licenses to Entergy Nuclear is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission. The NRC staff has further found that the application for the proposed license amendments complies with the standards and requirements of the Atomic Energy Act of 1954, as amended, and the Commission's rules and regulations set forth in 10 CFR Chapter I; the facility will operate in conformity with the application, the provisions of the Act and the rules and regulations of the Commission; there is reasonable assurance that the activities authorized by the proposed license amendments can be conducted without endangering the health and safety of the public and that such activities will be conducted in compliance with the Commission's regulations; the issuance of the proposed license amendments will not be inimical to the common defense and security or to the health and safety of the public; and the issuance of the proposed amendments will be in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied. The foregoing findings are supported by a Safety Evaluation dated April 29, 1999.

III.

Accordingly, pursuant to Sections 161b, 161i, and 184 of the Atomic Energy Act of 1954, as amended, 42 USC §§ 2201(b), 2201(i), and 2234, and 10 CFR 30.34, 40.41, 50.80, and 70.32, IT IS HEREBY ORDERED that the Commission consents to the transfer of the licenses as described herein to Entergy Nuclear, subject to the following conditions:

(1) For purposes of ensuring public health and safety, Entergy Nuclear shall provide decommissioning funding assurance of no less than $396 million, after payment of any taxes, in the decommissioning trust fund for Pilgrim upon the transfer of the Pilgrim licenses to Entergy Nuclear.

(2) Entergy Nuclear shall maintain the decommissioning trust funds in accordance with the application, this Order, and the related Safety Evaluation dated April 29, 1999, supporting this Order.

(3) Entergy Nuclear shall provide a Provisional Trust fund in the amount of $70 million, after payment of any taxes, in the Provisional Trust for Pilgrim upon the transfer of the Pilgrim licenses to Entergy Nuclear. The Provisional Trust shall be established and maintained in conformance with the representations made in the application.

(4) The Decommissioning Trust agreement(s) shall be in a form which is acceptable to the NRC and shall provide, in addition to any other clauses, that:

a) Investments in the securities or other obligations of Entergy Nuclear, Entergy Corporation, their affiliates, subsidiaries or associates, or their successors or assigns shall be prohibited. In addition, except for investments tied to market indexes or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants is prohibited.

b) The Director, Office of Nuclear Reactor Regulation, shall be given 30 days prior written notice of any material amendment to the trust agreement(s).

(5) Entergy Nuclear shall have access to a contingency fund of not less than fifty million dollars ($50m) for payment, if needed, of Pilgrim operating and maintenance expenses, the cost to transition to decommissioning status in the event of a decision to permanently shut down the unit, and decommissioning costs. Entergy Nuclear will take all necessary steps to ensure that access to these funds will remain available until the full amount has been exhausted for the purposes described above. Entergy Nuclear shall inform the Director, Office of Nuclear Reactor Regulation, in writing, at such time that it utilizes any of these contingency funds. This provision does not affect the NRC's authority to assure that adequate funds will remain available in the plant's separate decommissioning trust fund(s), which Entergy Nuclear shall maintain in accordance with NRC regulations. Once the plant has been placed in a safe-shutdown condition following a decision to decommission, Entergy Nuclear will use any remainder of the $50m contingency fund that has not been used to safely operate and maintain the plant to support the safe and prompt decommissioning of the plant, to the extent such funds are needed for safe and prompt decommissioning.

(6) Entergy Nuclear shall, prior to completion of the sale and transfer of Pilgrim to it, provide the Director, Office of Nuclear Reactor Regulation, satisfactory documentary evidence that Entergy Nuclear has obtained the appropriate amount of insurance required of licensees under 10 CFR Part 140 of the Commission's regulations.

(7) After receipt of all required regulatory approvals of the transfer of Pilgrim, Boston Edison and Entergy Nuclear shall inform the Director, Office of Nuclear Reactor Regulation, in writing of the date of the closing of the sale and transfer of Pilgrim no later than one business day prior to the date of closing. Should the transfer of the licenses not be completed by December 31, 1999, this Order shall become null and void, provided, however, on written application and for good cause shown, such date may in writing be extended.

IT IS FURTHER ORDERED that, consistent with 10 CFR 2.1315(b), license amendments that makes changes, as indicated in Enclosure 1 to this Order, to conform the licenses to reflect their transfer are approved. Such amendments shall be issued and made effective at the time the proposed license transfers are completed.

This Order is effective upon issuance.

For further details with respect to this Order, see the initial application dated December 21, 1998, and application supplements dated January 28, February 18, April 2, April 15, and April 16, 1999, which are available for public inspection at the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document room located at the Plymouth Public Library, 132 South Street, Plymouth, Massachusetts 02360.

Dated at Rockville, Maryland, this 29th day of April 1999.

FOR THE NUCLEAR REGULATORY COMMISSION

Samuel J. Collins, Director
Office of Nuclear Reactor Regulation

U.S. NUCLEAR REGULATORY COMMISSION

Amendment No. 01

MATERIALS LICENSE

Pursuant to the Atomic Energy Act of 1954, as amended, the Energy Reorganization Act of 1974 (Public Law 93-438), and Title 10, Code of Federal Regulations, Chapter I, Parts 30, 31, 32, 33, 34, 35, 36, 39, 40, and 70, and in reliance on statements and representations heretofore made by the licensee, a license is hereby issued authorizing the licensee to receive, acquire, possess, and transfer byproduct, source, and special nuclear material designated below; to use such material for the purpose(s) and at the place(s) designated below; to deliver or transfer such material to persons authorized to receive it in accordance with the regulations of the applicable Part(s). This license shall be deemed to contain the conditions specified in Section 183 of the Atomic Energy Act of 1954, as amended, and is subject to all applicable rules, regulations, and orders of the Nuclear Regulatory Commission now or hereafter in effect and to any conditions specified below.

Licensee	
1. Entergy Nuclear Generation Company Pilgrim Nuclear Power Station	In accordance with letter received December 23, 1998 3. License number 20-07626-04 is amended in its entirety to read as follows:
2. 600 Rocky Hill Road Plymouth, Massachusetts 02360-5599	4. Expiration date February 28, 2003 5. Docket No. 030-34378/20-07626-02 Reference No.

6. Byproduct, source, and/or special nuclear material	7. Chemical and/or physical form	8. Maximum amount that licensee may possess at any one time under this license
A. Any byproduct material with atomic numbers 1 through 83 inclusive	A. Contamination on reactor components	A. Not to exceed 30 millicuries per nuclide and 3 curies total
B. Any byproduct, source or special nuclear material with atomic numbers 84 through 96	B. Contamination on reactor components	B. Not to exceed 10 microcuries per nuclide and 100 microcuries total
C. Chromium-51	C. Contamination on reactor components	C. 75 millicuries
D. Manganese-54	D. Contamination on reactor components	D. 150 millicuries
E. Iron-55	E. Contamination on reactor components	E. 1620 millicuries
F. Iron-59	F. Contamination on reactor components	F. 45 millicuries
G. Cobalt-58	G. Contamination on reactor components	G. 45 millicuries
H. Cobalt-60	H. Contamination on reactor components	H. 830 millicuries

License Number
20-07626-04

Docket or Reference Number
030-34378/20-07626-02

Amendment No. 01

MATERIALS LICENSE
SUPPLEMENTARY SHEET

6. Byproduct, source, and/or special nuclear material	7. Chemical and/or physical form	8. Maximum amount that licensee may possess at any one time under this license
I. Nickel-63	I. Contamination on reactor components	I. 65 millicuries
J. Cesium-137	J. Contamination on reactor components	J. 130 millicuries
K. Plutonium-241	K. Contamination on reactor components	K. 95 microcuries

9. Authorized use:

A. through K. Decontamination, repair and testing of reactor components.

CONDITIONS

10. Licensed material may be used only at temporary job sites of the licensee anywhere in the United States where the Nuclear Regulatory Commission maintains jurisdiction for regulating the use of licensed material.

11. A. Licensed material shall be used by, or under the supervision of, Susan R. Landahl.

    B. The Radiation Safety Officer for this license is Susan R. Landahl.

12. In addition to the possession limits in Item 8, the licensee shall further restrict the possession of licensed material so that at no time is a quantity of radioactive material is possessed in excess of a quantity which requires consideration of the need for an emergency plan for responding to a release of licensed material in accordance with 10 CFR 30.72.

13. The licensee may transport licensed material in accordance with the provisions of 10 CFR Part 71, "Packaging and Transportation of Radioactive Material."

NRC FORM 374A U.S. NUCLEAR REGULATORY COMMISSION

License Number
20-07626-04

MATERIALS LICENSE
SUPPLEMENTARY SHEET

Docket or Reference Number
030-34378/20-07626-02

Amendment No. 01

14. Except as specifically provided otherwise in this license, the licensee shall conduct its program in accordance with the statements, representations, and procedures contained in the documents, including any enclosures, listed below. The Nuclear Regulatory Commission's regulations shall govern unless the statements, representations, and procedures in the licensee's application and correspondence are more restrictive than the regulations.

    A. Application dated March 12, 1990
    B. Letter received May 5, 1992
    C. Letter dated February 21, 1995
    D. Letter received December 23, 1998

For the U.S. Nuclear Regulatory Commission

Date ____________1999____________

By ________________________________

Duncan White
Division of Nuclear Materials Safety
Region I
King of Prussia, Pennsylvania 19406

84136475

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

BOSTON EDISON COMPANY

DOCKET NO. 50-293

PILGRIM NUCLEAR POWER STATION

AMENDMENT TO FACILITY OPERATING LICENSE

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment filed by the Boston Edison Company and Entergy Nuclear Generation Company, dated December 21, 1998, as supplemented January 28, February 18, April 2, April 15, and April 16, 1999, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended as indicated in the attachment to this license amendment, and paragraph 3.B of Facility Operating License No. DPR-35 is hereby amended to read as follows:

   3.B <u>Technical Specifications</u>

   The Technical Specifications contained in Appendix A, as revised through Amendment No. [*to be determined at time of transfer*], are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 30 days.

FOR THE NUCLEAR REGULATORY COMMISSION

Samuel J. Collins, Director
Office of Nuclear Reactor Regulation

Attachment: Changes to the Facility Operating License*
& Technical Specifications

Date of Issuance:

*Pages 1 - 6 are attached, for convenience, for the composite license to reflect these changes.

UNITED STATES

ATOMIC ENERGY COMMISSION

WASHINGTON, DC 20545

ENTERGY NUCLEAR GENERATION COMPANY*

(PILGRIM NUCLEAR POWER STATION)

DOCKET NO. 50-293

FACILITY OPERATING LICENSE

License No. DPR-35

The Atomic Energy Commission (the Commission) having found that:

a. Except as stated in condition 5, construction of the Pilgrim Nuclear Power Station (the facility) has been substantially completed in conformity with the application, as amended, the Provisional Construction Permit No. CPPR-49, the provisions of the Atomic Energy Act of 1954, as amended (the Act), and the rules and regulations of the Commission as set forth in Title 10, Chapter 1, CFR; and

b. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission; and

c. There is reasonable assurance (i) that the activities authorized by the operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission; and

d. The Entergy Nuclear Generation Company (Entergy Nuclear) is technically and financially qualified to engage in the activities authorized by this operating license, in accordance with the rules and regulations of the Commission; and

e. Entergy Nuclear has satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements" of the Commission's regulations; and

f. The issuance of this license will not be inimical to the common defense and security or to the health and safety of the public; and

g. In accordance with the requirements of Appendix D to 10 CFR Part 50, the operating license should be issued subject to conditions for protection of the environment set forth herein.

Facility Operating License No. DPR-35, dated June 8, 1972, issued to the Boston Edison Company (Boston Edison) is hereby amended in its entirety, pursuant to an Initial Decision dated September 13, 1972, by the Atomic Safety and Licensing Board, to read as follows:

*The Nuclear Regulatory Commission approved the transfer of the license from Boston Edison Company to Entergy Nuclear Generation Company on April 29, 1999.

1. This license applies to the Pilgrim Nuclear Power Station, a single cycle, forced circulation, boiling water nuclear reactor and associated electric generating equipment (the facility). The facility is located on the western shore of Cape Cod Bay in the town of Plymouth on the Entergy Nuclear site in Plymouth County, Massachusetts, and is described in the "Final Safety Analysis Report," as supplemented and amended.

2. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses Entergy Nuclear:

   A. Pursuant to the Section 104b of the Atomic Energy Act of 1954, as amended (the Act) and 10 CFR Part 50, "Licensing of Production and Utilization Facilities," to possess, use, and operate the facility as a utilization facility at the designated location on the Pilgrim site;

   B. Pursuant to the Act and 10 CFR 70, to receive, possess, and use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report, as supplemented and amended;

   C. Pursuant to the Act and 10 CFR Parts 30, 40 and 70 to receive, possess and use at any time any byproduct, source or special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

   D. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

   E. Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

3. This license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations; 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50 and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

   A. <u>Maximum Power Level</u>

   Entergy Nuclear is authorized to operate the facility at steady state power levels not to exceed 1998 megawatts thermal.

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

C. Records

Entergy Nuclear shall keep facility operating records in accordance with the requirements of the Technical Specifications.

D. Equalizer Valve Restriction - DELETED.

E. Recirculation Loop Inoperable

The reactor shall not be operated with one recirculation loop out of service for more than 24 hours. With the reactor operating, if one recirculation loop is out of service, the plant shall be placed in a hot shutdown condition within 24 hours unless the loop is sooner returned to service.

F. Fire Protection

Entergy Nuclear shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the facility and as approved in the SER dated December 21, 1978 as supplemented subject to the following provision:

Entergy Nuclear may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

G. Physical Protection

The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10CFR73.55 (51FR27817 and 27822) and to the authority of 10CFR50.90 and 10CFR50.54(p). The plans, which contain Safeguards Information protected under 10CFR73.21, are entitled: "Pilgrim Nuclear Power Station Physical Security Plan," with revisions submitted through September 18, 1987; "Pilgrim Nuclear Power Station Guard Training and Qualification Plan," with revisions submitted through September 24, 1984; and "Pilgrim Nuclear Power Station Safeguards Contingency Plan," with revisions submitted through February 15, 1984. Changes made in accordance with 10CFR73.55 shall be implemented in accordance with the schedule set forth therein.

H. Long Term Program

(1) The "Plan for the Long Term Program for Pilgrim Nuclear Power Station" (the Plan) submitted on May 7, 1984, is approved.

a) The Plan shall be followed by the licensee from and after the effective date of this amendment.

b) Changes to dates for completion of items identified in Schedule B of the Plan do not require a license amendment. Dates specified in Schedule A shall be changed only in accordance with applicable NRC procedure.

I. Post-Accident Sampling System, NUREG-0737, Item II.B.3, and Containment Atmospheric Monitoring System, NUREG-0737, Item II.F.1(6)

The licensee shall complete the installation of a post-accident sampling system and a containment atmospheric monitoring system as soon as practicable, but no later than June 30, 1985.

J. Additional Conditions

The Additional Conditions contained in Appendix B, as revised through Amendment No. 177, are hereby incorporated into this license. Entergy Nuclear shall operate the facility in accordance with the Additional Conditions.

K. Conditions Related to the Sale and Transfer

(1) For purposes of ensuring public health and safety, Entergy Nuclear shall provide decommissioning funding assurance of no less than $396 million, after payment of any taxes, in the decommissioning trust fund for Pilgrim upon the transfer of the Pilgrim licenses to Entergy Nuclear.

(2) Entergy Nuclear shall maintain the decommissioning trust funds in accordance with the application, this Order and the related Safety Evaluation dated April 29, 1999, supporting this Order.

(3) Entergy Nuclear shall provide a Provisional Trust fund in the amount of $70 million, after payment of any taxes, in the Provisional Trust for Pilgrim upon the transfer of the Pilgrim licenses to Entergy Nuclear. The Provisional Trust shall be established and maintained in conformance with the representations made in the application.

Revision 177,
Amendment ~~75~~, ~~85~~, ~~143~~, ~~177~~,

(4) Entergy Nuclear shall have access to a contingency fund of not less than fifty million dollars ($50m) for payment, if needed, of Pilgrim operating and maintenance expenses, the cost to transition to decommissioning status in the event of a decision to permanently shut down the unit, and decommissioning costs. Entergy Nuclear will take all necessary steps to ensure that access to these funds will remain available until the full amount has been exhausted for the purposes described above. Entergy Nuclear shall inform the Director, Office of Nuclear Reactor Regulation, in writing, at such time that it utilizes any of these contingency funds. This provision does not affect the NRC's authority to assure that adequate funds will remain available in the plant's separate decommissioning fund(s), which Entergy Nuclear shall maintain in accordance with NRC regulations. Once the plant has been placed in a safe-shutdown condition following a decision to decommission, Entergy Nuclear will use any remainder of the $50m contingency fund that has not been used to safely operate and maintain the plant to support the safe and prompt decommissioning of the plant, to the extent such funds are needed for safe and prompt decommissioning.

(5) The Decommissioning Trust agreement(s) shall be in a form which is acceptable to the NRC and shall provide, in addition to any other clauses, that:

a) Investments in the securities or other obligations of Entergy Nuclear, Entergy Corporation, their affiliates, subsidiaries or associates, or their successors or assigns shall be prohibited. In addition, except for investments tied to market indexes or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants is prohibited.

b) The Director, Office of Nuclear Reactor Regulation, shall be given 30 days prior written notice of any material amendment to the trust agreement(s).

4. This license is subject to the following condition for the protection of the environment: Boston Edison shall continue, for a period of five years after initial power operation of the facility, an environmental monitoring program similar to that presently existing with the Commonwealth of Massachusetts (and described generally in Section C-III of Boston Edison's Environmental Report, Operating License Stage dated September, 1970) as a basis for determining the extent of station influence on marine resources and shall mitigate adverse effects, if any, on marine resources.

5. Boston Edison has not completed as yet construction of the Rad Waste Solidification System and the Augmented Off-Gas System. Limiting conditions concerning these systems are set forth in the Technical Specifications.

6. Pursuant to Section 105c(8) of the Act, the Commission has consulted with the Attorney General regarding the issuance of this operating license. After said consultation, the Commission has determined that the issuance of this license, subject to conditions set forth in this subparagraph 6., in advance of consideration of and findings with respect to matters covered in Section 105c of the Act, is necessary in the public interest to avoid unnecessary delay in the operation of the facility. At the time this operating license is being issued an antitrust proceeding has not been noticed. The Commission, accordingly, has made no determination with respect to matters covered in Section 105c of the Act, including conditions, if any, which may be appropriate as a result of the outcome of any antitrust proceeding. On the basis of its findings made as a result of an antitrust proceeding, the Commission may continue this license as issued, rescind this license or amend this license to include such conditions as the Commission deems appropriate. Boston Edison and others who may be affected hereby are accordingly on notice that the granting of this license is without prejudice to any subsequent licensing action, including the imposition of appropriate conditions, which may be taken by the commission as a result of the outcome of any antitrust proceeding. In the course of its planning and other activities, Boston Edison will be expected to conduct itself accordingly.

7. This license is effective as of the date of issuance and shall expire June 8, 2012.

FOR THE ATOMIC ENERGY COMMISSION

Original Signed by A. Giambusso

A. Giambusso, Deputy Director for Reactor Projects
Directorate of Licensing

Attachments:
Appendix A - Technical Specifications (Radiological)

Date of Issuance: September 15, 1972

Amendment No. ~~134~~, ~~177~~,

ATTACHMENT TO LICENSE AMENDMENT

FACILITY OPERATING LICENSE NO. DPR-35

DOCKET NO. 50-293

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
Title Page Appendix A	Title Page Appendix A
Appendix B	Appendix B
4.0-1	4.0-1
5.0-2	5.0-2

APPENDIX A

TO

FACILITY OPERATING LICENSE DPR-35

TECHNICAL SPECIFICATION AND BASES

FOR

PILGRIM NUCLEAR POWER STATION

PLYMOUTH, MASSACHUSETTS

ENTERGY NUCLEAR

DOCKET NO. 50-293

4.0 DESIGN FEATURES

4.1 Site Location

Pilgrim Nuclear Power Station is located on the western shore of Cape Cod Bay in the Town of Plymouth, Plymouth County, Massachusetts and contains approximately 517 acres owned by Entergy Nuclear as shown on FSAR Figures 2.2-1 and 2.2-2. The site boundary is posted and a perimeter security fence provides a distinct security boundary for the protected area of the station.

The reactor (center line) is located approximately 1800 feet from the nearest property boundary.

4.2 Reactor Core

The reactor vessel core design shall be as described in the CORE OPERATING LIMITS REPORT and shall be limited to those fuel assemblies which have been analyzed with NRC approved codes and methods and approved by the NRC in its acceptance of Amendment 22 of GESTAR II.

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum k-infinity of 1.32 for standard core geometry, calculated at the burnup of maximum bundle reactivity, and an average U-235 enrichment of 4.6 % averaged over the axial planar zone of highest average enrichment; and

b. $K_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 10.3.5 of the FSAR.

(continued)

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the Pilgrim Station Final Safety Analysis Report (FSAR);

b. The Station Director shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

c. The Vice President - Operations for Pilgrim shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety; and

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures

5.2.2 Unit Staff

The unit staff organization shall include the following:

a. A non-licensed operator shall be on site when fuel is in the reactor and an additional non-licensed operator shall be assigned when the reactor is in an operational mode other than Cold Shutdown or Refueling.

(continued)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

PROPOSED TRANSFER OF OPERATING LICENSE AND MATERIALS LICENSE FOR

PILGRIM NUCLEAR POWER STATION

TO ENTERGY NUCLEAR GENERATION COMPANY

DOCKET NO. 50-293

LICENSE NO. DPR-35

1.0 INTRODUCTION

By application dated December 21, 1998, as supplemented January 28, February 18, April 2, April 15, and April 16, 1999, Boston Edison Company (Boston Edison) and Entergy Nuclear Generation Company (Entergy Nuclear) requested that the United States Nuclear Regulatory Commission (NRC) consent to the transfer of Operating License No. DPR-35 and Materials License No. 20-07626-04 for the Pilgrim Nuclear Power Station (Pilgrim). The applicants requested the transfer as a result of the Purchase and Sale Agreement signed by Boston Edison and Entergy Nuclear on November 18, 1998, under which Entergy Nuclear will purchase the Boston Edison Nuclear Business Unit, principally consisting of Pilgrim. Upon approval of the license transfers and consummation of the sale, control of the licenses for Pilgrim will be transferred from Boston Edison to Entergy Nuclear. The closing date for this sale is anticipated to be between April 1, 1999, and June 30, 2000, depending upon the applicants receiving various favorable regulatory approvals. The applicants also requested the approval of conforming license amendments to reflect the transfer of the licenses.

A meeting was held between Boston Edison, Entergy Nuclear and the NRC staff on December 9, 1998, to discuss the proposed transfer. Subsequently, based on a preliminary review of the initial application, the NRC staff determined that additional information regarding the technical qualifications of the new corporate management of Entergy Nuclear that would oversee the operation of Pilgrim was needed to complete the review. On January 22, 1999, the staff sent a Request for Additional Information (RAI) to Boston Edison. On January 28, 1999, Boston Edison and Entergy Nuclear responded to the RAI and expanded on previous information provided. A phone call was held between Boston Edison, Entergy Nuclear and the NRC staff on February 8, 1999, to discuss proposed changes to personnel titles in the Technical Specifications and the reporting structure between various Pilgrim onsite

ENCLOSURE 3

managers and the new Entergy Nuclear corporate level management. In a letter dated February 18, 1999, Boston Edison and Entergy Nuclear supplemented their application for conforming license amendments to request a proposed change to Technical Specification 5.2.1.c to further reflect the proposed transfer and Entergy Nuclear's management organization. As requested by the NRC staff, a copy of the Inter-Company Credit Agreement By and Between Entergy International Ltd. LLC (Entergy International) and Entergy Nuclear, dated March 31, 1999, was submitted on April 2, 1999, as proof of a $50 million credit line for exclusive use by Entergy Nuclear at Pilgrim. On April 15, 1999, Entergy Nuclear submitted information regarding the financial qualifications of Entergy International. The supplemental information and changes did not expand the scope of the application as originally noticed in the Federal Register.

This sale and transfer of Pilgrim is being undertaken by Boston Edison as part of the divestiture of all of its generating assets consistent with the restructuring of the electric utility industry occurring in Massachusetts. Boston Edison became a wholly owned subsidiary of BEC Energy, a Massachusetts business trust as a result of a corporate restructuring in 1997. Notwithstanding the restructuring, Boston Edison continued to be the holder of the Pilgrim operating license and the sole owner and operator of Pilgrim, and remained an electric utility as defined in 10 CFR 50.2.

As stated above, on November 18, 1998, Boston Edison entered into a purchase and sale agreement under which it will sell its interest in Pilgrim to Entergy Nuclear. Major issues addressed in the Purchase and Sale Agreement include:

> The final purchase price for Pilgrim is between $80 and $121 million, depending on the actual closing date, certain tax implications, and final fuel inventories at the time of closing.
>
> Upon closing and subject to the NRC's consent, Entergy Nuclear will assume title to the facility including all equipment, spare parts, fixtures, inventory, and other property necessary for the operation and maintenance of Pilgrim, and will take title to all spent nuclear fuel and other licensed materials at Pilgrim, and will assume all responsibility for the operation, maintenance, and eventual decommissioning of the unit.
>
> Upon closing, most, if not all, employees with Boston Edison Nuclear Business Unit will be offered employment with Entergy Nuclear.
>
> As part of the transaction, Boston Edison, Commonwealth Electric Company, and Montaup Electric Company have entered into power purchase agreements through the year 2004 with Entergy Nuclear under which Boston Edison, Commonwealth Electric Company and Montaup Electric Company will purchase capacity and electric energy from Pilgrim.
>
> At closing, Boston Edison will make additional deposits to the Pilgrim decommissioning trust fund to fully fund the radiological decommissioning costs consistent with the amounts determined in accordance with 10 CFR 50.75. Upon closing, Entergy Nuclear will be responsible for all Pilgrim decommissioning costs and activities, and Boston Edison's obligations shall be extinguished.

At closing, Boston Edison will transfer its currently held decommissioning trust fund to Entergy Nuclear.

Pilgrim Nuclear Power Station is a 670 megawatt electric, single unit, boiling water reactor. Upon purchase, Entergy Nuclear will operate, maintain and own Pilgrim, and will assume full liability and responsibility for decommissioning.

The relevant regulatory provisions governing the approval of the transfer of the operating license and materials license are 10 CFR 30.34, 40.41, 50.80, and 70.32. The Commission's regulations at 10 CFR 30.38, 40.44, 50.90, and 70.34 address the issuance of conforming license amendments.

2.0 FINANCIAL QUALIFICATIONS ANALYSIS

Entergy Nuclear does not qualify as an electric utility under 10 CFR 50.2. Therefore, to qualify to own and operate a nuclear power plant, Entergy Nuclear must provide information to demonstrate financial qualifications in accordance with 10 CFR 50.33(f).

The information must show:

1. As a non-electric utility applicant for an operating license, the applicant possesses or has reasonable assurance of obtaining the funds necessary to cover estimated operating costs for the period of the license. Also, it must submit estimated total annual operating costs for the first 5 years of facility operation and indicate the source(s) of funds to cover these costs.

2. As a newly formed entity organized primarily for the purpose of operating a nuclear power plant, the applicant must show (a) the legal and financial relationship it has or proposes to have with its stockholders or owners; (b) its financial ability to meet any contractual obligations to the entity which they have incurred or propose to incur; and (c) any other information considered necessary by the Commission to enable it to determine the applicant's financial qualification.

Entergy Nuclear provided financial information including a 5 year projection income statement and balance sheet, in its initial December 21, 1998, application.

The following financial qualifications analysis was conducted by the staff using and relying upon information provided by Entergy Nuclear in its application, which included Entergy Corporation annual reports for 1994 through 1997, and the Boston Edison Purchase and Sales Agreement. The licensee also responded to a written request and several oral requests for additional information by letters dated January 28, April 2, April 15, and April 16, 1999.

In its application, Entergy Nuclear states that it is an indirect, wholly owned subsidiary of Entergy Corporation, and is headquartered in New Orleans, Louisiana. Entergy Nuclear is a wholly owned subsidiary of Entergy Power Generation Corporation, which in turn is a wholly owned subsidiary of Entergy Corporation. Entergy Corporation is a U.S. based global energy company with power production, distribution operations and related diversified services. Entergy Corporation owns, manages or invests in power plants generating nearly 30,000

megawatts of electricity. Through its subsidiaries, Entergy Corporation indirectly owns and operates five nuclear power plants; Arkansas Nuclear One Units 1 & 2, Grand Gulf Nuclear Station, River Bend Station, and Waterford 3 Steam Electric Station. Entergy Corporation through its subsidiaries distributes energy to more than 2.5 million customers in the United States. As of September 30, 1998, Entergy Corporation has total assets of $27.4 billion. Over the past 3 years Entergy Corporation's standing with Moody's and Standard & Poors bond ratings have been between Baa3 to Baa2 and BBB- to BBB+ respectively. These bond ratings are considered "investment grade." In support of its claim that its third tier parent company, Entergy Corporation, is financially qualified to meet its commitments to Entergy Nuclear, the applicant submitted, as part of the license transfer application, annual reports for Entergy Corporation for the past 5 years and Moody's and Standard & Poor's bond ratings for the past 3 years. The staff finds that Entergy Nuclear's parent company is financially qualified to meet the commitments to Entergy Nuclear as specified in the application.

Entergy Nuclear was newly formed in 1998 as a subsidiary of Entergy Power Generation Corporation. In the application, Entergy Nuclear, stated that either through the parent company, associate company or affiliated company, it will provide the necessary funds with a guarantee, letter of credit or similar financial arrangement, to purchase Pilgrim. Through these same associations, Entergy Nuclear stated that it has assurance of obtaining the funds necessary to cover estimated operating costs of Pilgrim, if projected revenues should be temporarily lost due to an outage or similar event. In support of these claims, Entergy Nuclear has included, as part of the application, a guarantee which obligates Entergy International, another wholly owned subsidiary of Entergy Corporation, to irrevocably and unconditionally guarantee payment of all of Entergy Nuclear's obligations under the purchase and sale agreement of November 18, 1998, between Entergy Nuclear and Boston Edison, up to the amount of 50 million dollars. In addition, by letter dated April 2, 1999, Entergy Nuclear has provided an Inter-Company Credit Agreement between Entergy Nuclear and Entergy International, which obligates Entergy International to advance funds to Entergy Nuclear in an aggregate amount not to exceed $50 million for the purpose of providing financial assurance of sufficient funds for operation and maintenance of Pilgrim. The agreement provides that "in no event shall this Agreement be terminated, nor shall Entergy International Ltd. [LLC], cease to make advances under this Agreement, until the earlier of: (i) such time that Entergy Nuclear has permanently ceased operations at Pilgrim; or (ii) the NRC has given written approval of the discontinuance or termination of this Agreement", (Inter-Company Credit Agreement dated March 31, 1999).

On April 15, 1999, Entergy Nuclear submitted information to the NRC staff regarding the financial qualifications of Entergy International to meet its commitments to Entergy Nuclear. Entergy International is a wholly-owned subsidiary of Entergy Corporation. Entergy International was formed for the purpose of holding other subsidiaries involved in foreign electric utility businesses. The principal subsidiaries of Entergy International include Entergy London Investments plc, CitiPower Pty. and Entergy Power Edesur Holding, Ltd. Entergy International is a registered public utility holding company under the Public Utility Holding Company Act of 1935, as amended (PUHCA), and is subject to the broad regulatory provisions of PUHCA. This requires, among other things, Security and Exchange Commission (SEC) approval for certain transactions. For United States tax purposes, Entergy International is an affiliate of Entergy Corporation, and as such, its operations are included in the filing of Entergy Corporation's United States consolidated federal income tax return.

The NRC staff has reviewed the report of the independent accountants Coopers & Lybrand, dated March 4, 1999, along with the 1997 and 1998 consolidated financial statements of Entergy International, and concludes that Entergy International has sufficient cash and near-cash assets to fulfill its financial obligation to Entergy Nuclear if called upon, as stated in the Inter-Company Credit Agreement dated March 31, 1999.

Entergy Nuclear states that it will be able to call upon these funds, if necessary, to meet its expenses and obligations to safely operate and maintain the plant. These obligations include the costs of nuclear property damage insurance and any retrospective premium pursuant to 10 CFR 140.21. In the event of an extended shutdown, Entergy Nuclear would cover fixed operating expenses through its retained earnings, as available, or by funds provided as described above. In support of its claim that it would be able to meet fixed operating expenses for an extended shutdown, the license application included an estimate of fixed operating costs for a 6-month period for each year from 1999 to 2004.

(Shaded area contains proprietary information.)

In additional support of these claims that it has assurance of obtaining the funds necessary to cover the estimated operating costs of Pilgrim, Entergy Nuclear submitted as part of its license transfer application, copies of signed power purchase agreements with Boston Edison, Commonwealth Electric and Montaup Electric Company. Under these contracts, Entergy Nuclear states that it will sell 100 percent of Pilgrim's output at fixed prices "take or pay" through 2001. Beyond 2001, the contracted volumes begin to decline through 2004. (Pursuant to 10 CFR 50.33(f)(2), Entergy Nuclear submitted such projections over the 5-year period.) Entergy Nuclear will pursue other firm contracts or sell any uncommitted power into the New England market.

The following table summarizes the terms of the power purchase agreement and Entergy Nuclear's expected market prices for uncommitted power, as stated in the license transfer application:

YEAR	OUTPUT TO CONTRACT	CONTRACT PRICE (kWh)	MARKET PRICE (kWh)
1999	100%	3.50¢	
2000	100%	3.80¢	
2001	100%	3.52¢	
2002	80%	3.89¢	
2003	50%	4.35¢	
2004	50%	4.72¢	

(Shaded area contains proprietary information.)

Based on Pilgrim's current operating performance and Entergy Nuclear's program operating experience (from Entergy Corporation and Entergy Power Generation Corporation), Entergy Nuclear claims that it expects to operate Pilgrim at an average annual capacity factor of 85 percent and sell all power generated through firm contracts or into the New England market. The average capacity factor for Pilgrim from 1992 to 1997 was 76.6 percent. Entergy Nuclear expects to improve upon this historical capacity factor at Pilgrim based on its performance during refueling outages conducted at Entergy Corporation's other five nuclear units. In addition, Entergy Nuclear states that, at projected prices, based on independent market studies performed for it by ICF KAISER, and Entergy Power Marketing Group, these sales are expected to provide a margin of additional income over and above Pilgrim's operating costs.

The following table demonstrates, according to Entergy Nuclear, the ability of projected power sales to cover expected operating expenses:

($000)	1999	2000	2001	2002	2003	2004
Contract Power Sales	126,180	200,874	175,490	164,014	95,810	124,804
Market Power Sales	0	0	0	[redacted]	[redacted]	[redacted]
Total Revenue:	126,180	200,874	175,490	[redacted]	[redacted]	[redacted]
O & M *	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Depreciation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Admin & Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Expenses:	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Profit:	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Interest Expense:	[redacted]		[redacted]		[redacted]	[redacted]
Income Taxes:	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
Net Income/(Loss):	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

(Shaded area contains proprietary information.)

*In the above table, "Admin & Other" pertains to administrative expenses, fringe benefits, payroll taxes, and ad valorem taxes. [redacted]

(Shaded area contains proprietary information.)

At the closing of the Pilgrim purchase, Entergy Nuclear states that it will provide additional financial assurance up to $50 million by means of the Inter-Company Credit Agreement dated March 31, 1999, as discussed above.

The NRC staff conducted sensitivity analyses on the projected income statement provided by the applicant in order to judge the financial resiliency of Entergy Nuclear to weaker-than-projected revenue. Although expense projections are the domain of the applicant, the staff believes that the applicant's assumptions are reasonable. For example, based on Entergy Corporation's annual reports for 1994 through 1997, these projected expenses fall in line with historical trends. However, the revenue projections are sensitive to the unit's capacity factor and projected market prices in the years 2002 to 2004.

One set of sensitivity analyses adopted the assumption that capacity factors dropped by 10 percentage points below those assumed by Entergy Nuclear. With all other assumptions held constant, the staff found that Entergy Nuclear would be able to sustain the reduced revenues over the 5 ½-year projection period submitted (1999 to 2004) and would have the financial capability of maintaining the unit in a safe manner.

In another set of sensitivity analyses, projected market prices for the years 2002 through 2004, were assumed to be 10 dollars less per megawatt-hour than projected by the applicant. With all other assumptions held constant, the results showed that Entergy Nuclear would be capable of sustaining such a drop in market prices. However, the staff's assumption, for sensitivity purposes only, is that this seems to be highly unlikely given the North American Electric Reliability Council's (NERC) Reliability Assessment for 1998 through 2007, dated October 1998. In the Reliability Assessment report, NERC predicts that the Northeast Power Coordinating Council (United States) (NPCC(US)), which includes Pilgrim, will see generating capacity margins dropping from 17.3 percent in 1998 to 5.0 percent in 2007. Such a trend would indicate that market prices are subject to upward pricing pressure. Therefore, the staff finds that the applicant's assumptions for market prices are reasonable, as shrinking generating capacity margins should cause market prices of electricity to increase in the area, assuming other factors remain equal.

Although these sensitivity analyses indicate lower earnings for Entergy Nuclear, if lower capacity or lower market prices are experienced compared to their forecast, Entergy Nuclear should still be able to remain financially stable through the use of retained earnings, or either through the parent, associate, or affiliate company guarantee, letter of credit, or similar financial arrangement to provide additional necessary funds, as described above.

The staff concludes that attempting to forecast the growth rate, or even the direction of change, for market-based prices in the Pilgrim market area is too speculative, given the uncertainty of deregulation, and other unknown factors potentially affecting electricity capacity or prices, to be useful for its contingency analysis. The staff's conclusion from this analysis is that, even if prices for Pilgrim power were to change at an average annual rate much lower than anticipated by Entergy Nuclear, this does not preclude Entergy Nuclear from operating and maintaining Pilgrim in a manner that would protect public health and safety.

2.1 <u>NRC Staff Conclusions With Respect To Financial Qualifications</u>

On the basis of the information provided in the application, along with the independent sensitivity analyses conducted by the NRC staff, the staff finds that Entergy Nuclear has

provided reasonable assurance that it is able to obtain adequate funding and it has provided adequate assurance that it will be able to cover estimated operating costs, as well as sufficient documentation of specific legal and financial relationships that supports this conclusion.

The staff further finds that Entergy Nuclear has fulfilled its requirements under 10 CFR 50.33(f), "to demonstrate to the Commission the financial qualification of the applicant to carry out, in accordance with regulations in this chapter, the activities for which the permit or license is sought."

However, to ensure that adequate funds are available as necessary to cover operating costs, if necessary during operation of the facility during an extended shutdown or similar event, the NRC staff believes that the commitment stated in the Inter-Company Credit Agreement dated March 31, 1999, and in the application, to make available to Entergy Nuclear $50 million should be made a condition of the license and of the Order approving the transfer of the Pilgrim licenses as follows:

> Entergy Nuclear shall have access to a contingency fund of not less than fifty million dollars ($50m) for payment, if needed, of Pilgrim operating and maintenance expenses, the cost to transition to decommissioning status in the event of a decision to permanently shut down the unit, and decommissioning costs. Entergy Nuclear will take all necessary steps to ensure that access to these funds will remain available until the full amount has been exhausted for the purposes described above. Entergy Nuclear shall inform the Director, Office of Nuclear Reactor Regulation, in writing, at such time that it utilizes any of these contingency funds. This provision does not affect the NRC's authority to assure that adequate funds will remain available in the plant's separate decommissioning fund(s), which Entergy Nuclear shall maintain in accordance with NRC regulations. Once the plant has been placed in a safe-shutdown condition following a decision to decommission, Entergy Nuclear will use any remainder of the $50m contingency fund that has not been used to safely operate and maintain the plant to support the safe and prompt decommissioning of the plant, to the extent such funds are needed for safe and prompt decommissioning.

3.0 DECOMMISSIONING FUNDING ASSURANCE

The NRC has determined that the requirements to provide assurance of decommissioning funding and provision of an adequate amount of decommissioning funding are necessary to ensure the adequate protection of public health and safety.

3.1 Amount Of Decommissioning Funds

Pursuant to 10 CFR 50.75(b), each power reactor licensee must certify that it will provide decommissioning funding assurance in an amount that may be more but not less than the formulas in 10 CFR 50.75(c)(1) and (2). These formulas are based on the size and type of reactor, and on cost escalation factors for labor, energy, and low-level waste (LLW) disposal costs.

In its application for transfer of the Pilgrim operating license, Entergy Nuclear indicates that, as a condition of the sale, the current owner and licensee, Boston Edison, has agreed to fund the decommissioning trust fund for a total that will range, depending on closing date conditions, between $396 million and $466 million. This amount is based on a site-specific cost estimate performed for Pilgrim in 1998. The current Entergy Nuclear cost estimate is higher than the NRC minimum amount due to the inclusion of spent fuel storage costs and costs to remove non-radioactive structures. The NRC's regulations in 10 CFR 50.75(e) allow licensees to take a credit of up to a 2 percent annual real rate of return on decommissioning trust funds on deposit. This credit may be applied toward the current estimate of decommissioning funds needed for decommissioning at the time of permanent cessation of operations. At the time that Entergy Nuclear expects Pilgrim to permanently cease operations in 2012, this 2 percent credit would cause the decommissioning trust fund to grow to a range of $512 million to $602 million, depending on the actual decommissioning funds at the time of closing.

The LLW disposal cost factor is to be derived from the latest version of NUREG-1307, Revision 8, "Report on Waste Burial Charges." NUREG-1307 Rev. 8, allows licensees a variety of methods by which they may estimate disposal costs of LLW, including disposition by waste vendors. (See page 6, Example 3 in NUREG-1307 Rev. 8.) In supplemental information dated January 28, 1999, responding to an NRC request for additional information, Entergy Nuclear calculated the required funding using the formulas in 10 CFR 50.75(c) using NUREG-1307, Rev. 8. Based on this minimum requirement calculation, Entergy Nuclear concludes that it currently must certify that it will provide at least $327 million to comply with the requirements of 10 CFR 50.75(b). The NRC staff has verified Entergy Nuclear's calculation and determined that this amount is accurate.

3.2 NRC Staff Conclusion On Amount Of Decommissioning Funds

On the basis of the information in the Entergy Nuclear application, as cited herein, the NRC staff concludes that Entergy Nuclear has complied with the requirements in 10 CFR 50.75(b) with respect to the amount of decommissioning funds that Entergy Nuclear must certify that it will provide. The amount that Entergy Nuclear proposes to have placed in the decommissioning fund is greater than the approximately $327 million that is required under the generic formulas in 10 CFR 50.75(c). Additionally, Entergy Nuclear will be required to adjust the amount required to be available for decommissioning funding on an annual basis, pursuant to 10 CFR 50.75(b). However, in view of Boston Edison's commitment, included in the terms of the sale of Pilgrim, to prefund the Pilgrim decommissioning trust from between $396 Million and $466 Million, the NRC staff believes that the following condition should be applied as a license condition:

> For purposes of ensuring public health and safety, Entergy Nuclear shall provide decommissioning funding assurance of no less than $396 million, after payment of any taxes, in the decommissioning trust fund for Pilgrim upon the transfer of the Pilgrim licenses to Entergy Nuclear.

3.3 Decommissioning Funding Assurance Mechanism

Pursuant to 10 CFR 50.75(b), a reactor licensee is required to provide decommissioning funding assurance by one or more of the methods described in 10 CFR 50.75(e), as determined to be acceptable to the NRC. Entergy Nuclear has chosen to provide decommissioning funding assurance by means of one or more fully-funded, external trust funds, as provided in 10 CFR 50.75(e)(1)(i).

Entergy Nuclear states in its application that on the closing date, Boston Edison will fully fund and transfer to Entergy Nuclear, in accordance with Section 5.21 of the Purchase and Sale Agreement between Boston Edison and Entergy Nuclear, an aggregate amount equal to or greater that the minimum amount required by the NRC regulations for the decommissioning of Pilgrim. Boston Edison will deposit funds into a Decommissioning Trust and a Provisional Trust sufficient to satisfy the minimum decommissioning funding requirements prescribed by 10 CFR 50.75(c) at the expiration of the current Pilgrim Facility Operating License. Based upon varying Federal income tax and closing date assumptions, the total amount of decommissioning funds to be transferred to Entergy Nuclear at closing is projected to be from $396 million to $466 million. The applicant states that these funds will provide sufficient funds for decommissioning by the expiration of Pilgrim's current facility operating license. In its January 28, 1999, submittal, the applicant stated that upon closing Entergy Nuclear will be solely liable for decommissioning. Any additional required decommissioning funds would be provided through a parent, associate, or affiliate company guarantee, letter of credit or similar financial arrangement. In supplemental information supplied on April 16, 1999, Entergy Nuclear indicated that any funds remaining in the $50 million contingency fund provided by Entergy International, after Pilgrim has been placed in a safe-shutdown condition following a decision to decommission, will be used as needed to support the safe and prompt decommissioning of Pilgrim. That commitment will be made a license condition, as discussed in section 2.0, above.

In the license transfer application, Entergy Nuclear states that the Purchase and Sale agreement conditions the sale, the decommissioning trust funding, and the transfer on the absence of adverse federal income tax consequences as a result thereof on either party. Boston Edition and Entergy Nuclear have filed IRS ruling requests to allow decommissioning trust funding and transfer to occur without adverse tax consequences.

The Purchase and Sale Agreement provides for the decommissioning trust funds to be transferred at the time of closing through the transfer of two separate decommissioning trusts - a regular Decommissioning Trust and, if necessary, a Provisional Trust. In its January 28, 1999, letter to the NRC, Entergy Nuclear stated that the purpose of the Provisional Trust is to set aside a portion of the pre-paid decommissioning amount that is subject to be refunded by Entergy Nuclear to Boston Edison should changes in the tax qualification of the fund occur after closing. The applicants stated that a favorable change in the tax qualification status would increase the after-tax earnings rate on the fund, thereby reducing the required initial pre-payment. The applicant stated that if there are no intervening favorable changes in the tax law, rule or regulation prior to closing, then the amount of funds in the Provisional Trust will be $70 million. If there are intervening changes, either before closing or between closing and

December 31, 2002, then the amount in the Provisional Trust will be reduced in accordance with Schedule 5.21 of the Purchase and Sale Agreement and the reduction will be rebated to Boston Edison in accordance with the terms of the Provisional Trust. Any reduction will be accomplished in a manner consistent with the Atomic Energy Act of 1954, as amended, IRS requirements, and any other applicable law. The Purchase and Sale Agreement provides that in no event shall the amount in the trusts available to decommission Pilgrim fall below the NRC required minimum. After December 31, 2002, all funds remaining in the Provisional Trust will be transferred to the regular Decommissioning Trust and Boston Edison shall have no further claim to those funds.

The NRC staff concludes that reasonable assurance of decommissioning funding will be provided by the method proposed by Entergy Nuclear provided that: 1) the decommissioning trust is maintained in accordance with the license transfer application, the requirements of the transfer order, and this safety evaluation and fully complies with the requirements of NRC regulations; 2) the decommissioning trust agreement is in a form acceptable to the NRC and contains certain NRC staff-required clauses; and 3) the Provisional Trust is established and maintained in accordance with the representations made in the license application.

3.3.1 NRC Staff Required Decommissioning Trust Clauses

The NRC staff requires that the following clauses be included in the trust agreement as a condition for staff approval:

(1) Investments in the securities or other obligations of Entergy Nuclear, Entergy Corporation, their affiliates, subsidiaries or associates, or their successors or assigns shall be prohibited. In addition, except for investments tied to market indexes or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants is prohibited.

(2) The Director, Office of Nuclear Reactor Regulation, shall be given 30 days prior written notice of any material amendment to the trust agreement.

3.3.2 NRC Staff Conclusion On Funding Assurance Mechanism

On the basis of the information in the Entergy Nuclear license application and the representations made therein, and subject to the conditions discussed above, the NRC staff concludes that the funding assurance transfer and the funding assurance mechanism meet the requirements of 10 CFR 50.75 and provide reasonable assurance of the availability of funds for decommissioning Pilgrim.

The staff further concludes that the following license conditions should be included in the license:

1. Entergy Nuclear shall maintain the decommissioning trust funds in accordance with the application, this Order and the related Safety Evaluation dated April 29, 1999, supporting this Order.

2. Entergy Nuclear shall provide a Provisional Trust fund in the amount of $70 million, after payment of any taxes, in the Provisional Trust for Pilgrim upon the transfer of the Pilgrim licenses to Entergy Nuclear. The Provisional Trust shall be established and maintained in conformance with the representations made in the application.

3. The Decommissioning Trust agreement(s) shall be in a form which is acceptable to the NRC and shall provide, in addition to any other clauses, that:

   a) Investments in the securities or other obligations of Entergy Nuclear, Entergy Corporation, their affiliates, subsidiaries or associates, or their successors or assigns shall be prohibited. In addition, except for investments tied to market indexes or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants is prohibited.

   b) The Director, Office of Nuclear Reactor Regulation, shall be given 30 days prior written notice of any material amendment to the trust agreement(s).

4.0 ANTITRUST

Section 105 of the Atomic Energy Act of 1954, as amended (AEA), requires the Commission to conduct an antitrust review in connection with an application for a license to construct or operate a facility under Section 103 of the AEA. Because Pilgrim is licensed under Section 104b, it is not subject to antitrust review by the Commission.

5.0 FOREIGN OWNERSHIP, CONTROL OR DOMINATION

According to the application, all of the officers and directors of Entergy Nuclear are U.S. Citizens. Entergy Nuclear is incorporated in Delaware, and has its principal office in Jackson, Mississippi. The application states that "Entergy Nuclear Generation Company is not owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government". The NRC staff does not know or have reason to believe otherwise.

6.0 NUCLEAR INSURANCE

The provisions of the Price-Anderson Act (Section 170 of the AEA) and 10 CFR Part 140 require that Entergy Nuclear be added to the current Pilgrim indemnity agreement. In accordance with the Price-Anderson Act, Entergy Nuclear must provide primary insurance of $200 million and participate in the secondary retrospective insurance pool once it becomes a licensee. These requirements can be met by purchasing insurance policies from the nuclear liability insurance pool, American Nuclear Insurers. Entergy Nuclear also will be required to maintain property insurance as specified in 10 CFR 50.54(w). The staff does not have any reason to believe that Entergy Nuclear will be unable to meet the statutory and regulatory insurance requirements applicable to all power reactor licensees.

Consistent with NRC practice, the staff will require Entergy Nuclear to provide satisfactory documentary evidence that Entergy Nuclear has obtained the appropriate amount of insurance required of licensees under 10 CFR Part 140 of the Commission's regulations, prior to the issuance of the amended licenses reflecting Entergy Nuclear as the licensee. Since the issuance of the amended licenses is directly tied to the consummation of the sale and transfer of Pilgrim, the order approving the transfer will contain the following condition:

> Entergy Nuclear shall, prior to completion of the sale and transfer of Pilgrim to it, provide the Director, Office of Nuclear Reactor Regulation, satisfactory documentary evidence that Entergy Nuclear has obtained the appropriate amount of insurance required of licensees under 10 CFR Part 140 of the Commission's regulations.

7.0 TECHNICAL QUALIFICATIONS

7.1 Basis and Guidance for NRC Evaluation

The staff used the following regulations and guidance in making its evaluation of Entergy Nuclear's technical qualifications: 10 CFR 50.40(b), "Common Standards;" Standard Review Plan (SRP) NUREG-0800, Section 13.1.1, "Management and Technical Support Organization;" SRP, Sections 13.1.2-13.1.3, "Operating Organizations," and Section 4.6.1 of American National Standards Institute (ANSI) N18.1-1971, "Selection and Training of Nuclear Power Plant Personnel," as endorsed by Regulatory Guide 1.8, Revision 2, April 1987, "Qualification and Training of Personnel for Nuclear Power Plants."

7.2 Evaluation

The purpose of this review is to ensure that Entergy Nuclear's corporate organization and technical staff are or will be sufficiently qualified to provide support for safe plant operation.

7.2.1 Management and Technical Support Organization

SRP Section 13.1.1 criteria (underlined in the following discussion) for analyzing the management and technical support organization of Entergy Nuclear are discussed below.

<u>The organizational groups responsible for implementation of technical support for operation of the facility are identified and described.</u> The Boston Edison Nuclear Business Unit (not limited to site location) which includes all groups responsible for implementation of technical support for operation of Pilgrim will be maintained under Entergy Nuclear as currently described in the final safety analysis report (FSAR). These groups include those responsible for various functions such as Maintenance and Operations, and support functions such as Engineering and Business Services. Corporate support service such as Human Resources and Accounting, currently provided by Boston Edison, will be provided by Entergy Nuclear. Since the FSAR for Pilgrim identifies and describes the technical support groups for the site, Entergy Nuclear will review any changes to the site organization under and subject to 10 CFR 50.59.

<u>The organizational structure provides for the integrated management of activities that support the operation and maintenance of Pilgrim</u>. Currently, all plant departments (e.g., Operations, Maintenance, Chemistry, Radiation Protection, etc.) report to the Vice President-Nuclear/ Station Director. With the purchase of Pilgrim by Entergy Nuclear, the only change to the existing organization will be that the plant operating organizations will report to the Vice President-Operations for Pilgrim, who previously was the Vice President-Nuclear. Otherwise, the existing organizational structure, which has been acceptable, will not change as a result of the sale.

<u>Clear management control and effective lines of authority and communications exist between the organizational units involved in the management, operations, and technical support for operation of Pilgrim</u>. In a supplement to the application dated January 28, 1999, several organization charts were submitted that depict the proposed relationship between Entergy Nuclear and the current Pilgrim site organization. The submittals also described the management and communications pathways that will exist between the Entergy Nuclear corporate management and the Pilgrim plant operations and support groups. The current Pilgrim Vice President-Nuclear and Station Director will become the Station Director only and will report to the Vice President-Operations, who will be located at the Pilgrim site and will report directly to the President and Chief Executive Officer (CEO), Entergy Nuclear. The reporting and communication chain from Pilgrim operations and support groups through the Vice President-Operations, to the President, Entergy Nuclear allows Pilgrim management access to additional Entergy Nuclear resources that may be needed to support plant operation.

<u>Substantive breadth and level of experience and availability of personnel exist to implement the responsibility for technical support for operation of Pilgrim</u>. In the supplement to the application dated January 28, 1999, Boston Edison and Entergy Nuclear provided resumes of the persons to fill key management positions.

The two most senior Entergy Nuclear management personnel, who are assigned responsibilities in the Entergy Nuclear corporate structure, exhibit sufficient experience and nuclear knowledge to implement their individual responsibilities for technical support for the operation of Pilgrim. Both individuals have in excess of 20 years of experience in the management, operations, and maintenance of commercial nuclear power facilities. Additionally, they meet the required qualifications described in Regulatory Guide 1.8 and ANSI-N18.1-1971, "Selection and Training of Nuclear Power Plant Personnel." Existing Pilgrim licensing documents, which are not proposed to be changed, will ensure that any new management employees placed at Pilgrim will have experience in the day-to-day operation of nuclear plants and will meet all applicable technical qualifications.

<u>The corporate level management and technical support structure should be free of ambiguous assignments of primary responsibility. A corporate officer should clearly be responsible for nuclear activities, without having ancillary responsibilities that might detract from attention to nuclear safety matters</u>. The supplement to the application dated January 28, 1999, states that the Vice President-Operations at the site will be the officer responsible for implementing all activities associated with the overall safe and reliable operation of Pilgrim. The Vice President-Operations will be clearly responsible for nuclear activities and will not have non-nuclear

ancillary responsibilities. Based on the Vice President-Operations being the corporate officer responsible for the safe operation of Pilgrim, the staff concludes that corporate level management will not be detracted from attention to nuclear safety matters.

7.2.2 Operating Organization

Since there will be no material changes to the Pilgrim operating organization, it will continue to perform the same activities through the existing lines of authority and communication. Based on the commitment of Entergy Nuclear to maintain the personnel qualifications level, the staff concludes that the proposed Pilgrim operating organization is acceptable and meets the criteria described in SRP Section 13.1.2-13.1.3, "Operating Organization."

7.3 Staff Conclusions With Respect To Technical Qualifications

Entergy Nuclear has described its management organization and personnel qualifications for the operation of the facility after the license transfer. Entergy Nuclear has proposed no material changes to the existing organizational structure. Entergy Nuclear has stated that any changes to the organization within the first year of the sale will be reported to the staff. In addition, Entergy Nuclear has stated that most if not all employees within the Boston Edison Nuclear Business Unit will be offered employment with Entergy Nuclear. All positions that need to be refilled will be with persons who are qualified under the appropriate licensing documents. The staff concludes that Entergy Nuclear has or will have the management and technical support organization necessary to support plant operation and has an acceptable organization and adequate resources to provide technical support for the operation of Pilgrim under both normal and off-normal conditions.

Accordingly, on the basis of the foregoing discussion and the information and representations in the application, the staff finds that Entergy Nuclear is technically qualified to hold the Pilgrim license, as required under 10 CFR 50.40(b).

8.0 MATERIALS LICENSE

The application requested approval of the transfer of Materials License No. 20-07626-04 to Entergy Nuclear. The request was evaluated in light of NRC Information Notice No. 89-25, Revision 1 "Unauthorized Transfer of Ownership or Control of Licensed Activities," which attaches a listing of information that should be considered. Based on the above evaluation of technical qualifications of Entergy Nuclear and the information provided by the applicants, the NRC staff concludes that the transfer of the Materials License to Entergy Nuclear is in accordance with the provisions of the Atomic Energy Act.

9.0 CONFORMING AMENDMENT

9.1 Introduction

As stated previously, Boston Edison and Entergy Nuclear have requested approval of proposed conforming amendments to the Pilgrim Facility Operating License No. DPR-35, and

Materials License No. 20-07626-04. The requested changes for the most part replace references to Boston Edison or its organizations or officials in the licenses with references to Entergy Nuclear or its organizations or officials to reflect the proposed transfer of the licenses and change of ownership. In addition, the application included two changes, to page one of the operating license, to add a reference to the Nuclear Regulatory Commission (to update an existing reference to the Atomic Energy Commission), and a reference to the transfer approval. Supplemental information and a request for one conforming change involving Technical Specification 5.0 (Administrative Controls) subsection 5.2.1.c, to change the title of "Senior Vice President-Nuclear " (a Boston Edison title) to "Vice President-Operations for Pilgrim" (an equivalent Entergy Nuclear title), received after the initial *Federal Register* notice of the application did not affect the applicability of the Commission's generic no significant hazards consideration determination set forth in 10 CFR 2.1315.

9.2 Discussion

The changes to be made to the licenses are indicated in Enclosure 1. On page one of the Operating License, the two requested changes specifically identified above have been modified by the staff and combined into a footnote to be inserted at the bottom of the first page of the license in order to be more consistent with NRC practice. Regarding the proposed change to TS 5.2.1.c, while the title for the senior manager on site was changed, the responsibilities of this managerial position are to be maintained in accordance with the current technical specifications. The changes as indicated in Enclosure 1 do no more than accurately reflect the approved transfer action, which is subject to certain conditions set forth in the Order approving the transfer. These conditions were identified and discussed earlier in this Safety Evaluation. The amendments involve no safety questions and are administrative in nature. Accordingly, the proposed amendments are acceptable.

9.3 CONCLUSION WITH RESPECT TO THE CONFORMING AMENDMENTS

The Commission has concluded, based on the considerations discussed above, that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

10.0 COMMENTS RECEIVED

The NRC has received comments from Citizens Urging Responsible Energy (CURE) dated February 25, 1999, and from 13 municipalities that purchase power from Boston Edison dated February 25, 1999.

10.1 CURE Comments

CURE expressed specific concerns about the operation and maintenance of Pilgrim by Boston Edison. Based on CURE's stated belief that Pilgrim has had a "seriously flawed health and safety record," CURE has requested the following:

1) That BECo make available to the public the site characterization study that it has,

2) That a review of the site, including a radiological survey, be performed to verify the site's current compliance with all applicable regulations, and

3) That the NRC take the necessary steps to ensure that the health and safety issues raised in Exhibits A through H of CURE's submittal are fully investigated and resolved.

CURE's comments and exhibits do not raise any issues material to the NRC's approval of a license transfer, such as the technical or financial qualifications of the proposed transferee. The NRC, of course, may not approve the transfer unless Entergy Nuclear is fully qualified to hold the license for the plant. Since a transferee takes the plant as it exists, any "seriously flawed health and safety record" will become the transferee's responsibilities to correct.

Addressing the specific requests by CURE, the NRC has performed a review of the mini-site characterization study that was performed by Boston Edison. This study was commissioned by Entergy Nuclear as a prudency report supporting the sale. Boston Edison has stated this report is the property of Entergy Nuclear and CURE should approach Entergy Nuclear for its release. The NRC review in Inspection Report 99-01 concluded that significant amounts of radioactive contamination were not present in onsite surface soils and appropriate records of spills and other unusual occurrences involving the spread of contamination were maintained in accordance with 10 CFR 50.75(g). There were no open issues raised as a result of our review.

The plant is constantly monitored in accordance with the Technical Specifications, under various safety programs and inspections, and by the resident inspectors, to ensure that the plant is in compliance with NRC Regulations. The staff is unaware of any non-compliance of any significance which, in particular, would be a bar to approving the transfer.

CURE has submitted several exhibits in support of its comments. The staff has reviewed these exhibits and determined that in general, the issues raised were the result of various NRC inspections. The regional staff tracks all open issues raised in inspection reports and attempts to close them in a timely manner. All open issues are tracked as Inspector Follow Items (IFI) or unresolved items (URI). These items are managed by an open items list maintained by the inspectors. There are no specific open items related to the exhibits provided by CURE.

In summary, CURE has raised no issues that would preclude the staff from approving the transfer of the Pilgrim operating license or materials license to Entergy Nuclear.

10.2 <u>Comments By Thirteen Municipal Customers of Pilgrim</u>

Thirteen municipalities which purchase power from Pilgrim (13 Municipals) have requested that the NRC make available the information redacted from the application to the 13 Municipals. According to the 13 Municipals, they have long-term contracts with Boston Edison on file with the Federal Energy Regulatory Commission (FERC) to purchase power from Pilgrim. Boston Edison has filed a petition with FERC to permit it to modify the contracts in light of the proposed transfer of the plant to Entergy Nuclear. The 13 Municipals state that they do not

oppose the transfer, but oppose the "unilateral" reformation of the long-term contracts by Boston Edison. They assert that they are seeking the redacted financial information "to access the potential impact of the proposed contract changes," and to assess whether Boston Edison's actions will affect Entergy Nuclear's financial capabilities.

The staff has fully analyzed Entergy Nuclear's financial qualifications, taking into account all facts and circumstances contained in the application, including the proprietary information withheld from the public. The staff has determined that Entergy Nuclear is financially qualified to hold the licenses, as discussed earlier. The 13 Municipals have not cited any legal basis for the staff to release the proprietary information contained in the application, or suggested that there is reason to believe that with the proprietary information they would arrive at a conclusion different from the staff concerning Entergy Nuclear's financial qualifications. Since the matter is now pending before FERC, it would appear that relief would be more appropriately sought in that forum.

11.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Massachusetts State Official was notified of the proposed issuance of the amendments. The State official had no comments.

12.0 ENVIRONMENTAL CONSIDERATION

The subject application is for approval of the transfer of licenses issued by the NRC and approval of conforming amendments. Accordingly, the action involved meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(21). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with approval of the application.

13.0 CONCLUSIONS

In view of the foregoing, the NRC staff concludes that Entergy Nuclear is technically and financially qualified to purchase, operate and decommission the Pilgrim Nuclear Power Station, and otherwise qualified to hold the operating license for Pilgrim. Also, the staff concludes that there do not appear to be any problematic antitrust or foreign ownership considerations that would arise from the proposed sale. The staff also concludes that the transfer of the materials license to Entergy Nuclear is in accordance with the provisions of the Atomic Energy Act, and that the transfer of the operating license to Entergy Nuclear is consistent with applicable provisions of law, regulations, and orders issued by the Commission. Accordingly, with the imposition of the conditions discussed above relating to funding of the Decommissioning Trust, Provisional Trust, and the $50 million contingency fund as discussed earlier, and relating to required insurance, approval of the proposed action is acceptable.

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United States Government Accountability Office

GAO

Report to the Subcommittee on Energy and Water Development, Committee on Appropriations, House of Representatives

September 2008

NUCLEAR WASTE

Action Needed to Improve Accountability and Management of DOE's Major Cleanup Projects

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Highlights

Highlights of GAO-08-1081, a report to the Subcommittee on Energy and Water Development, Committee on Appropriations, House of Representatives

NUCLEAR WASTE

Action Needed to Improve Accountability and Management of DOE's Major Cleanup Projects

Why GAO Did This Study

The Department of Energy (DOE) spends billions of dollars annually to clean up nuclear wastes at sites that produced nuclear weapons. Cleanup projects decontaminate and demolish buildings, remove and dispose of contaminated soil, treat contaminated groundwater, and stabilize and dispose of solid and liquid radioactive wastes. Ten of these projects meet or nearly meet DOE's definition of major: costs exceeding $1 billion in the near term—usually a 5-year window of the project's total estimated life cycle.

GAO was asked to determine the (1) extent to which the cost and schedule for DOE's major cleanup projects have changed and key reasons for changes, and (2) factors that may hinder DOE's ability to effectively manage these projects. GAO met with project directors and reviewed project documents for 10 major cleanup projects: 9 above the near-term $1 billion threshold, and 1 estimated to cost between $900 million and $1 billion over the near term.

What GAO Recommends

GAO is making a number of recommendations, such as expanding the content of performance reports provided to DOE senior managers and information provided to Congress to better reflect current status of near-term and life cycle baseline cost and schedules and reasons for significant changes; and strengthening DOE guidance and baseline reviews, among other things. In commenting on a draft of this report, DOE agreed with GAO's recommendations.

To view the full product, including the scope and methodology, click on GAO-08-1081. For more information, contact Gene Aloise at (202) 512-3841 or aloisee@gao.gov.

What GAO Found

Nine of the 10 cleanup projects GAO reviewed had life cycle baseline cost increases, from a low of $139 million for one project to a high of nearly $9 billion for another, and life cycle baseline schedule delays from 2 to 15 years. These changes occurred primarily because the baselines we reviewed included schedule assumptions that were not linked to technical or budget realities, and the scope of work included other assumptions that did not prove true. Specifically, the schedules for 8 of the 10 projects were established in response to DOE's 2002 effort to complete cleanup work, which in some cases moved up project completion dates by 15 years or more. For example, to meet the 2012 accelerated completion date for its solid waste disposition project, DOE's Idaho National Laboratory assumed it would process waste at a rate that was more than 50 percent higher than the rate demonstrated at the time it established the baseline. When the laboratory could not meet that processing rate, DOE revised its baseline, adding 4 years and about $450 million to the project. Also, most of the 10 projects had cost increases and schedule delays because the previous baselines (1) had not fully foreseen the type and extent of cleanup needed, (2) assumed that construction projects needed to carry out the cleanup work would be completed on time, or (3) had not expected substantial additional work scope.

DOE has not effectively used management tools—including independent project baseline reviews, performance information systems, guidance, and performance goals—to help oversee major cleanup projects' scope of work, costs, and schedule. For example, DOE's independent reviews meant to provide reasonable assurance that a project's work can be completed within the baseline's stated cost and schedule, have not done so for 4 of 10 projects. For one project, the baseline was significantly modified as little as 7 months after it had been revised and validated by the independent review, while other projects have experienced life cycle cost increases of as much as $9 billion and delays of up to 10 years, within 1 to 2 years after these reviews. In addition, although DOE uses several types of reporting methods for overseeing cleanup projects, these methods do not always provide managers with the information needed to effectively oversee the projects or keep Congress informed on the projects' status. For example, sites' proposals for changes to projects' cost and schedule baselines do not always identify possible root causes, and DOE does not systematically analyze the proposals for common problems across its projects. Therefore, DOE may be missing opportunities to improve management across projects. In addition, guidance for key management and oversight functions are spread across many different types of documents and are unclear and contradictory. As a result, project managers do not consistently implement this guidance, which may lead, for example, to problems in effectively managing risks across projects. Finally, DOE recently changed its goals for "successful" cleanup projects, reducing the amount of work and raising the allowable cost increases against the near-term baseline. DOE has initiated several actions to improve project management, but it is too early to determine whether these efforts will be effective.

Contents

Abbreviations

Army Corps	Army Corps of Engineers
DOE	Department of Energy
EM	Office of Environmental Management
EVM	earned value management
OECM	Office of Engineering and Construction Management
OMB	Office of Management and Budget
QPR	quarterly project review
WTP	Waste Treatment Plant

United States Government Accountability Office
Washington, DC 20548

September 26, 2008

The Honorable Peter J. Visclosky
Chairman
The Honorable David L. Hobson
Ranking Member
Subcommittee on Energy and Water Development
Committee on Appropriations
House of Representatives

The Department of Energy (DOE) spends billions of dollars annually to clean up nuclear wastes at sites across the nation that produced nuclear weapons. Cleanup projects decontaminate and demolish buildings, remove and dispose of contaminated soil, treat contaminated groundwater, and stabilize and dispose of solid and liquid radioactive wastes, among other things. DOE's Office of Environmental Management (EM) currently oversees more than 80 of these cleanup projects, primarily at government-owned, contractor-operated sites throughout the nation. Some of these highly complex projects have completion dates beyond 2050. Ten of these projects meet or nearly meet DOE's definition of "major": projects whose costs exceed $1 billion in the near-term—usually a 5-year window of the project's total estimated life cycle.[1],[2] These 10 projects have combined estimated near-term costs of almost $19 billion and combined life cycle costs estimated to range between $115 billion and $143 billion, and they account for almost half of EM's $5.5 billion fiscal year 2009 budget request.[3] These 10 projects are described in detail in appendix II and include the remediation, decontamination, and decommissioning, or the stabilization and disposition of:

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[1]For this review, we lowered the threshold to $900 million out of concern that some projects not now considered major would become major because of increases in costs, which resulted in the addition of one project to our review (the solid waste stabilization and disposition project at the Hanford Site, near Richland, Washington).

[2]We did not review one major project still in the early stages of development (the nuclear facility decontamination and decommissioning project in Portsmouth, Ohio).

[3]DOE defines life cycle costs as the sum total cost of the direct, indirect, and other related costs incurred or estimated to be incurred in the design, development, production, operation, maintenance, support, and final disposition of a major system over its anticipated useful life span.

- solid waste at Idaho National Laboratory, Idaho;
- nuclear facilities at the East Tennessee Technology Park, Oak Ridge Reservation, Tennessee;
- nuclear materials at the Savannah River Site, South Carolina;
- radioactive liquid tank waste at the Savannah River Site, South Carolina;
- soil and water at Los Alamos National Laboratory, New Mexico;
- nuclear materials at the Hanford Site, Washington;
- solid waste at the Hanford Site, Washington;
- soil and water at the Hanford Site, Washington;
- nuclear facilities at the River Corridor Closure Project, Hanford Site, Washington; and
- radioactive liquid tank waste at the Office of River Protection, Hanford Site, Washington.[4]

DOE established Order 413 in 2000 to provide project management guidance for construction projects—projects that build large complexes often housing unique equipment and technologies that process waste or other radioactive material—and nuclear waste cleanup projects.[5],[6] In 2005 and 2007, EM, in conjunction with DOE's Office of Engineering and Construction Management (OECM), issued further guidance to better tailor the order's requirements to the cleanup projects. This guidance lays out protocols directing DOE project managers to establish a life cycle

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[4]Hanford's radioactive liquid tank waste stabilization and disposition project is administered by the Office of River Protection, while the other four major cleanup projects at Hanford are administered by DOE's Richland office.

[5]Order 413.3 was issued in 2000 and amended in 2006, and is now referred to as 413.3A. For this report, we use DOE Order 413 to refer to the order in effect, unless otherwise specified.

[6]We have reported on DOE's management of these construction projects. See GAO, *Department of Energy: Major Construction Projects Need a Consistent Approach for Assessing Technology Readiness to Help Avoid Cost Increases and Delays*, GAO-07-336 (Washington, D.C.: Mar. 27, 2007).

baseline for cleanup projects that includes three key parts: (1) prior year actual costs; (2) a near-term estimate of the scope of the cleanup work (the cleanup activities needed to achieve project goals), cost, and schedule of the cleanup activities (the near-term is generally for 5 years, or the duration of the contract, whichever is longer); and (3) out-year estimates through project completion for those projects that extend beyond the near term.[7] The near-term and out-year estimates also identify the amount of contingency monies that could be needed to cover potential project risks.[8]

Major cleanup projects take years to complete, and often involve unique challenges and a high degree of complexity; therefore, it is critically important that EM develop and implement a rigorous, disciplined approach for developing and managing the baselines. Such an approach includes planning and managing work activities, cost, and schedule to achieve project goals in a stable, controlled manner over the near term and the entire life of the project. DOE has taken several steps to establish such an approach, including the following:

- EM must formally approve changes to the near-term and life cycle baseline.
- Project managers must provide formal and informal reports to DOE headquarters staff, including data entries into databases and quarterly performance reports. These reports contain, among other things, earned value management (EVM) data—a measure of progress against a cost and schedule baseline. Widely used in industry, earned value data makes it possible for managers and others to determine how a project has been performing and to predict future performance trends. Furthermore, both the Office of Management and Budget (OMB) and DOE Order 413 require

[7] In previous years, DOE presented out-year estimates as a single point estimate based on the most probable cost and schedule of its projects. In 2007, DOE developed out-year estimates with cost and schedule ranges to account for the uncertainty associated with long-term projects. The low end of the range is based on the amount of funding needed with a 50 percent level of confidence that the project will be successfully completed, while the high end of the range is based on an 80 percent level of confidence. As discussed elsewhere in this report, DOE does not fund its contingency accounts for these projects.

[8] Contingency funds are funds that may be needed to cover potential cost increases stemming from a variety of project risks, including technical complexities, regulatory issues, and funding shortfalls.

the use of EVM data, and GAO has developed best practices on how to use the data.[9]

- As stipulated in DOE Order 413, OECM must independently review project baselines at critical project stages; OECM conducts these reviews largely with the help of external technical experts. Specifically, for cleanup projects that cost $100 million or more, OECM must review a project's proposed baseline to provide reasonable assurance that the project can be successfully executed. OECM also examines technical scope, cost, schedule, and avoidance and mitigation plans for possible cost and schedule overruns, as well as proposed project management.

Overall, we and others have reported over the past two decades that project management weaknesses have impaired DOE's major projects. In 1990, we designated DOE's contract management (which includes project management) as a high-risk area for fraud, waste, abuse, and mismanagement. In addition, in 1999, the National Academies' National Research Council developed recommendations to address weaknesses in DOE's project management. Recently, in 2007, we reported that DOE had improved its approach to project management but that performance on DOE's projects had not substantially improved.[10] Also in 2007, the National Academy of Public Administration reported specifically on EM's management of nuclear waste and complimented EM on its improvements in project management, but also raised questions about EM's ability to follow through on them. Furthermore, reviews by DOE's Office of Inspector General, the Department of Defense's Army Corps of Engineers (Army Corps), and the National Research Council, among others, have advised DOE on how to better manage its major projects.

In this context, you asked us to determine the (1) extent to which the cost and schedule for DOE's major cleanup projects have changed and the key reasons for these changes, and (2) factors that may hinder DOE's ability to effectively manage these cleanup projects.

To determine the extent to which DOE cleanup projects are experiencing cost or schedule changes and key reasons contributing to these changes,

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[9]GAO, *Cost Assessment Guide: Best Practices for Estimating and Managing Program Costs*, GAO-07-1134SP (Washington D.C.: July 2007).

[10]GAO, *Department of Energy: Consistent Application of Requirements Needed to Improve Project Management*, GAO-07-518 (Washington, D.C.: May 11, 2007).

we spoke with DOE project directors and reviewed project management documents for 10 of EM's major cleanup projects—9 projects above the near-term $1 billion threshold, and 1 estimated to cost between $900 million and $1 billion over the near term. For our analysis, we examined the life cycle baseline reported as of the most recent contract awards or major contract modifications—which occurred between 2004 and 2007—and compared these baselines with the updated baselines at the time of our review (dollar amounts used in calculating cost increases are in fiscal year constant 2008 dollars). We conducted site visits and analyzed project documentation, such as project plans, independent reviews, contractor performance data, plans to avoid or mitigate project risks, and documents prepared to guide and control formal changes to the baseline. We also identified factors that may hinder DOE's ability to effectively manage projects in accordance with approved life cycle baselines primarily through a review of project documents and interviews with project officials. Because we and others have previously expressed concern about the data reliability of a key DOE project management tracking database—the Project Assessment and Reporting System—we did not develop conclusions or findings based on information generated through that system.[11] Instead, we collected information directly from project site offices and contractors. In addition, we spoke with officials from EM and OECM in Washington, D.C. We provided an interim briefing to the Subcommittee on the status of our work on April 3, 2008.

We conducted this performance audit from March 2007 to September 2008 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives. Appendix I contains a detailed description of our scope and methodology.

Results in Brief

Nine of the 10 cleanup projects we reviewed have experienced cost increases and schedule delays in their life cycle baseline, ranging from

[11]See, for example, GAO, *Department of Energy: Further Actions Are Needed to Strengthen Contract Management for Major Projects*, GAO-05-123 (Mar. 18, 2005); and Civil Engineering Research Foundation, *Independent Research Assessment of Project Management Factors Affecting Department of Energy Project Success* (Washington, D.C., July 12, 2004).

$139 million for one project to more than $9 billion for another, and schedule delays ranging from 2 years to 15 years. These changes arose primarily because the initial baselines made schedule assumptions that were not linked to technical or budget realities, and the scope of work included other assumptions that did not prove true. Specifically:

- *Baselines were not linked to technical or funding realities*. The schedules for 8 of the 10 projects we reviewed were established in response to EM's 2002 effort to accelerate cleanup work, which in some cases moved up project completion dates by 15 years or more. EM wanted to complete cleanups earlier to better safeguard public health and the environment, among other things. However, these dates were not always tied to technical capabilities or likely funding realities. For example, to meet the 2012 accelerated completion date for its solid waste disposition project, DOE's Idaho National Laboratory assumed its waste treatment plant could process waste at a rate that was more than 50 percent higher than the rate demonstrated at the time EM established the baseline. When the waste treatment plant did not meet that processing rate, EM revised its baseline, deferring 4 years of cleanup work, which added about $450 million to the project. In addition, before April 2007, according to several EM officials, project managers were directed to establish cost baselines to meet the accelerated schedules without considering likely funding for the projects. As a result, most projects did not receive funding as planned for in the baselines, hindering their ability to complete the work on time. In April 2007, EM changed its strategy: It limited its funding for all sites and directed that future baselines be based on the expected budget for each site. In part because of this change, some completion dates were extended by as much as 15 years.

- *Baselines' scope of work included optimistic assumptions that did not prove true*. Most of the projects we reviewed also experienced cost increases and schedule delays because the initial baselines had (1) not fully anticipated the type and extent of cleanup that would be needed, (2) assumed that construction projects needed to carry out the cleanup work would be completed on time, or (3) assumed the scope of work activities needed to finish the project would not increase. For example, at a 1940s-era building being demolished at Oak Ridge as part of the nuclear facility decontamination and decommissioning project, the contractor found that the building was far more contaminated and deteriorated than first estimated and had to reinforce the structure in order to safely remove contaminated equipment before demolishing the building. Primarily because these activities had not been adequately anticipated in the baseline, project costs rose by $1.2 billion and completion was extended by 9 years, to 2017. Similarly, the baselines for four of the major cleanup

projects assumed that a related, major construction project would be completed on schedule and available for the cleanup project to use. For example, a 5-year delay in the completion of Hanford's major construction project—the Waste Treatment Plant (WTP)—was the most significant factor behind extending the radioactive liquid tank waste project's schedule by 10 years, and increasing its life cycle costs by $4.8 billion. The delay in WTP's startup date resulted in additional years required to store the waste in the tanks and then to operate the treatment plant.

DOE has not always effectively used management tools—including independent project baseline reviews, performance information systems, guidance, and performance goals—to help oversee major cleanup projects' scope of work, costs, and schedule. Specifically:

- DOE's independent reviews of project baseline estimates, meant to, among other things, provide reasonable assurance that a project's work activities can be accomplished within the baseline's stated cost and schedule, have not done so for 4 of the 10 projects we reviewed. The baselines for these 4 projects were significantly modified shortly after review, revision, and validation. For one project, the baseline was significantly modified as little as 7 months after it had been revised and validated based on the independent review, while other projects had experienced additional life cycle cost increases of as much as $9 billion and delays of up to 10 years, within 1 to 2 years after the baseline reviews. As a result, the usefulness of the independent baseline reviews is questionable when significant baseline changes occur very shortly after the reviews are completed.

- EM managers do not always receive the information needed to effectively manage major cleanup projects or provide detailed reports to Congress on the projects' status. First, sites' proposals for changes to cost and schedule baselines do not consistently identify reasons for the changes or possible root causes, and EM does not systematically analyze the proposals for common problems across its projects. As a result, EM may be missing opportunities to apply lessons learned across projects. Second, in certain cases, the use of EVM data did not conform to industry standards or best practices identified by GAO, in part because the data contained anomalies that skewed analyses or lacked important information on future staffing needs. Third, EM's quarterly performance reports neither consistently provide accurate information about a project's performance against the near-term baseline, nor do they include information about how current performance may affect the life cycle baseline. Finally, DOE's reports to Congress do not include important information that would aid oversight, such as the extent of and reasons for significant changes to near-term and life cycle baseline estimates. In contrast, Department of Defense reports to

Congress on acquisitions for major systems provide detailed information on significant cost and schedule changes and the reasons for those changes.

- Guidance for key management and oversight functions—such as project baseline development, risk management, and contingency funding—is not consolidated, and is contradictory and unclear. Consequently, project managers do not consistently implement this guidance. For example, DOE headquarters officials found that project managers are calculating contingency funding to cover project risks in their baselines in a variety of ways, leading to uncertainty regarding the total contingency funds needed to cover all cleanup projects.

- DOE recently changed its goals for the performance of cleanup projects. Before 2008, a major cleanup project was expected to achieve 100 percent of the scope of work in its life cycle baseline with less than a 10 percent cost increase in the project's life cycle baseline. However, according to EM's current cleanup project performance goal, the projects are successful if they achieve at least 80 percent of the scope of work in their near-term baselines with less than a 25 percent cost increase. The new performance goal permits up to 20 percent of the scope of work to be deferred from the near term to out years, creating a substantially greater risk that life cycle costs will continue to increase and that completion dates will be delayed. According to DOE officials, the agency adjusted performance goals primarily to account for the greater level of uncertainty inherent in cleanup projects. However, by lowering expectations for adhering to near-term baselines, DOE may inadvertently be creating an environment in which large increases to life cycle costs become not only more common, but accepted and tolerated.

- Over the past 2 years, EM has begun a series of efforts to better manage its projects and address long-standing problems. For example, under its "Best-in-Class" Project Management Initiative, EM senior managers have expressed a strong commitment to improving project performance, and under this initiative, EM contracted with the Army Corps to assess project management, and then identified 18 priority actions to correct known problems. Although these efforts are ongoing, EM has yet to combine them into a formal plan, and it is too early to tell whether these efforts will prove effective.

We are making a number of recommendations to the Secretary of Energy to improve management of major cleanup projects, including to report more complete information to senior DOE management and Congress so that they can be fully informed about project status and make informed

decisions about these projects; consolidate, clarify, and update guidance for managing cleanup projects; consolidate all planned and ongoing EM improvements into a comprehensive corrective action plan; and develop the independent baseline reviews to better assure that project work scope can be completed within the baselines' stated cost and schedule.

We provided a draft of this report to the Department of Energy for its review and comment. DOE agreed with our recommendations but provided some suggested changes to them, and provided specific comments on the overall report, which we incorporated as appropriate. We discuss DOE's comments in detail at the end of this letter. DOE also provided some technical comments, which we incorporated as appropriate. DOE's comments are provided in appendix IV.

Background

DOE oversees and implements its major cleanup projects through agreements with contractors who operate the nuclear weapons research and production sites and the cleanup projects at those sites. Some of EM's cleanup projects are located at DOE sites administered by the National Nuclear Security Administration, a separately organized agency within DOE.

EM's major cleanup projects involve efforts to clean up sites where nuclear weapons were produced and production waste stored.[12] EM's cleanup projects handle a wide array of waste types and levels of radioactivity and hazardous constituents, and can involve multiple activities to, among other things, retrieve, characterize, treat, package, store, transport, and dispose of the waste, as well as disassemble, treat, package, store, transport, and dispose of the contaminated containers or processing lines/equipment used for weapons production or for storing or treating the waste. Multiple EM cleanup projects can occur at a single DOE site responsible for a multitude of other noncleanup-related activities. The cleanup projects are organized generally around similar waste types and activities. For example, the soil and water remediation activities at each site are organized under one umbrella, as are the nuclear facility decontamination and decommissioning projects, and the radioactive liquid tank waste projects, among others. EM generally

[12]DOE defines a project as a unique effort that supports a program mission and that has defined points for starting and ending; is undertaken to create a product, facility, or system; and contains interdependent activities planned to meet a common objective or mission.

manages these similar work activities, grouped into a category known as a Project Baseline Summary, through numerical designations; for example, all activities for soil and water remediation are grouped under Project Baseline Summary 30. (See app. II for additional information on the 10 DOE major cleanup projects reviewed.)

Funding for and Costs of DOE's Major Cleanup Projects

Unlike construction projects, which are funded on a line item basis, cleanup projects receive funding through operating funds designated for each DOE site. In 2003, EM began applying project management principles contained in DOE Order 413 to these cleanup projects in order to apply more discipline and rigor in planning and expending these project funds, among other things.

A cleanup project can cost several billion dollars and its life cycle can span several decades. EM divides the life cycle baselines for its major cleanup projects into three distinct parts—prior year costs, near term (usually a 5-year period), and out year (through project completion). Life cycle costs for each project range from a low of almost $1.7 billion to over $44 billion, and some projects might not be completed until after 2050.[13] (See app. III for detailed information on the life cycle baseline costs for the 10 projects we reviewed.)

EM applies different approaches to managing these wastes, depending on the type and extent of contamination and the state or federal regulatory guidelines and milestones it needs to comply with. DOE has agreements with state and federal regulators to clean up sites, and the agreements lay out a framework for determining the cleanup standards to be met. Furthermore, because all projects have a certain degree of uncertainty, such as not fully knowing the condition of buried waste containers, EM needs to plan for this uncertainty and identify ways to prevent serious disruption to projects should problems arise. To address this uncertainty, DOE Order 413 requires project managers to identify contingency funds that may be needed to cover potential cost increases stemming from a variety of project risks, including technical complexities, regulatory issues, and funding shortfalls. Although EM project managers build contingency funding into their near-term and out-year estimates, EM management does not generally include funding in its budget requests to cover contingency for cleanup projects until after it is actually needed to address a problem;

[13]In current year dollars, and excluding EM contingency funding.

therefore, EM contingency for cleanup projects has been referred to as "unfunded contingency."

Earned Value Management for Tracking Work Progress

To be effective, program managers need information on program deliverables and on the progress made in meeting them. One method that can help program managers track this progress is EVM data. These data include, for example, detailed information on budgeted costs and actual costs for work scheduled and work performed, as well as forecasted costs at project completion. Among other things, EVM data can be used to compare (1) budgeted costs to actual costs and (2) the value of work accomplished during a given period with the value of work scheduled for that period. By using the value of work completed as a basis for estimating the cost and time to complete a project, EVM data should alert program managers to potential problems sooner than expenditures alone can.

As a key management tool, EVM has evolved from an industrial engineering concept to a government and industry best practice to better oversee programs. Both OMB and DOE Order 413 require the use of EVM. OMB Circular A-11, part 7, requires the use of an integrated EVM system across an entire program to measure how well the government and its contractors are meeting a program's approved cost, schedule, and performance goals. The American National Standards Institute and the Electronic Industries Alliance have jointly established a national standard for EVM systems.[14] Recognizing the benefits of having these national standards, OMB states in its 2006 Capital Programming Guide that major acquisitions that require product development are to require that contractors use an EVM system that meets the American National Standards Institute guidelines.[15] In addition, DOE Order 413 requires that projects with total cleanup costs of $50 million or more use an EVM system that complies with industry standards and is certified by DOE's OECM to comply with these standards.

[14]See, for example, ANSI/EIA 748 32 Industry Guidelines (American National Standards Institute/Electronic Industries Alliance Standard, Earned Value Management Systems, ANSI/EIA-748-A-1998 (R2002), approved May 19, 1998, revised January 2002).

[15]See OMB, Capital Programming Guide, II.2.4, Establishing an Earned Value Management System. The OMB requirements also are reflected in the Federal Acquisition Regulation at 48 C.F.R. subpart 34.2.

GAO also has developed EVM best practices that, when followed, can help project managers consistently develop and analyze EVM data to gain a complete and accurate understanding of project status. Among other things, our guidance on EVM states that (1) EVM data should not have data errors and anomalies that may skew and distort the EVM analysis, and (2) information such as staffing levels and the root causes of and corrective actions for cost and schedule variances should be reported through the EVM system.

Major Cleanup Projects Experienced Billions of Dollars in Additional Costs and Schedule Delays, Primarily because Initial Baselines Were Overly Optimistic

Nearly all the cleanup projects we reviewed have had cost increases and schedule delays in the life cycle baseline, as much as $9 billion for one project, and schedule delays of as much as 15 years for two projects. These cost increases and schedule delays occurred primarily because the previous baselines for these projects had schedule assumptions that were not linked to technical or budget realities, and other assumptions also proved to be overly optimistic.

Major Cleanup Projects' Costs Have Increased by Billions and Schedules Have Been Delayed by As Much As 15 Years

The estimated costs of the 9 of the 10 DOE major cleanup projects we reviewed have significantly exceeded original estimates, as table 1 shows.

Table 1: Changes in the Estimated Life Cycle Costs for DOE Major Cleanup Projects

Dollars in billions

Project	Previous life cycle cost estimate (year of estimate)[a]	Current life cycle cost estimate range[b]	Life cycle cost increase range[b]	Percentage increase range[b,c]
Solid waste stabilization and disposition, Idaho National Laboratory	$2.851 (2006)	$3.301 – $3.940	$.450 – $1.089	16% – 38%
Nuclear facility decontamination and decommissioning, Oak Ridge Reservation	1.907 (2004)	3.126 – 3.290	1.219 – 1.383	64 – 73
Nuclear material stabilization and disposition, Savannah River Site	7.487 (2004)	10.802 – 11.248	3.315 – 3.761	44 – 50
Radioactive liquid tank stabilization and disposition, Savannah River Site	11.909 (2004)	18.622 – 24.003	6.714 – 12.094	56 – 102
Soil and water remediation, Los Alamos National Laboratory	1.521 (2006)	1.660 – 2.425	.139 – .904	9 – 59
Nuclear material stabilization and disposition, Hanford Site	2.990 (2006)	3.387 – 3.412	.397 – .422	13 – 14
Solid waste stabilization and disposition, Hanford Site	8.219 (2007)	9.596 – 10.639	1.377 – 2.420	17 – 29
Soil and water remediation, Hanford Site	3.902 (2007)	5.623 – 5.759	1.721 – 1.857	44 – 48
Nuclear facility decontamination and decommissioning, Hanford Site[d]	4.762 (2006)	4.762 – 4.892	0	0
Radioactive liquid tank stabilization and disposition, Hanford Site	21.647 (2004)	31.048 – 39.694	9.401 – 18.048	43 – 83

Source: GAO analysis of DOE data.

[a]For purposes of this report, previous cost estimates are the life cycle cost estimates created at the beginning of the most recent contract period for operation of the DOE site or the most recent major contract modification or extension, which in many cases coincided with the beginning of the project's previous near-term baseline. Current life cycle cost estimates are based on the most recently approved near-term baseline, out-year planning estimate ranges, or both.

[b]EM recently began using cost estimate ranges rather than point estimates. According to EM officials, costs at the lower end of the ranges were estimated at the 50 percent level of confidence, while costs at the upper end of the ranges represent the 80 percent level of confidence. For this report, our analysis of cost change uses the lower end of the range, which excludes contingency, because contingency amounts can vary widely between projects and are not typically funded before they are needed.

[c]We calculated the percentage of cost increase on the basis of constant 2008 dollars to make them comparable across projects and to show real increases in cost while excluding increases due to inflation.

[d]As of August 2008, this project has not registered a cost increase. However, project officials told us that they expect to file a baseline change proposal increasing the life cycle cost by at least several hundred million dollars by the end of December 2008.

As the table shows, estimated costs increased from a minimum of $139 million for one project to more than $9 billion for another project. The smallest dollar and percentage increase—$139 million, or 9 percent—occurred at Los Alamos' soil and water remediation project, which is focused on cleaning up known or suspected chemical and radiological contamination in addition to treating soil and groundwater that was contaminated by this waste. This project, however, is expected to further increase its life cycle cost estimate. The largest dollar increase among the 10 major projects—more than $9 billion—was for Hanford's radioactive liquid tank waste project, which is expected to remove, treat, and dispose of more than 56 million gallons of high-level radioactive waste in 177 underground storage tanks. In fact, the other radioactive liquid tank waste project, at Savannah River, registered the second largest dollar increase—almost $7 billion. However, the largest percentage increase—about 64 percent—occurred at Oak Ridge's nuclear facilities decontamination and decommissioning project.

Table 2 shows that 8 of the 10 projects we reviewed experienced delays in scheduled project completion, ranging from 2 years to 15 years.[16]

Table 2: Changes in Estimated Project Schedules for DOE Major Cleanup Projects

Project	Previous completion date estimate[a]	Current completion date estimate[a]	Schedule change (years)
Solid waste stabilization and disposition, Idaho National Laboratory	2012	2016 – 2020	4 – 8
Nuclear facility decontamination and decommissioning, Oak Ridge Reservation	2008	2017	9
Nuclear material stabilization and disposition, Savannah River Site	2015	2024 – 2026	9 – 11
Radioactive liquid tank stabilization and disposition, Savannah River Site	2019	2032 – 2034	13 – 15
Soil and water remediation, Los Alamos National Laboratory[b]	2015	2015	0
Nuclear material stabilization and disposition, Hanford site	2016	2018 – 2019	2 – 3

[16]EM recently began using schedule estimate ranges rather than point estimates. According to EM officials, scheduled completion dates at the lower end of the ranges were estimated at the 50 percent level of confidence, while dates at the upper end of the ranges represent the 80 percent level of confidence. For this report, our analysis of schedule change uses the lower end of the range.

Project	Previous completion date estimate[a]	Current completion date estimate[a]	Schedule change (years)
Solid waste stabilization and disposition, Hanford site	2035	2050 – 2058	15 – 23
Soil and water remediation, Hanford site	2035	2050 – 2059	15 – 24
Nuclear facility decontamination and decommissioning, Hanford site	2019	2019	0
Radioactive liquid tank stabilization and disposition, Hanford site	2032	2042 – 2050	10 – 18

Source: GAO analysis of DOE data.

[a]For purposes of this report, previous project completion dates represent the estimates at the beginning of the new contract period for operation of the DOE site or the major contract modification or extension, which typically coincided with the beginning of the projects' current or previous near-term baseline. Current completion date estimates represent the most recently approved near-term baseline or out-year planning estimate ranges calculated at the 50 percent confidence level at the lower end of the range, to the 80 percent level of confidence at the higher end of the range. EM recently began using schedule estimate ranges rather than point estimates. For this report, our analysis of schedule change uses the lower end of the range.

[b]The June 2008 Baseline Change Proposal shows proposed costs associated with this project at the 80 percent confidence level would extend through fiscal year 2020.

As table 2 shows, the shortest delay is at Hanford's nuclear material stabilization and disposition project, while the longest delays—15 years—also are at Hanford: the soil and water remediation and the solid waste stabilization and disposition projects.

Overly Optimistic Baselines Contributed to Significant Changes in Projects' Life Cycle

The changes in schedule and costs occurred primarily for two reasons. First, initial project baselines were built on accelerated schedules that were not always linked to technical capabilities or available budgets, although EM has begun to tie its new baselines to anticipated funding. Second, the initial baselines included other assumptions that did not hold true, including conditions on the ground at the sites, expected completion dates for related construction projects, and activities that would be included in projects' scopes of work.

Baseline Schedules Were Not Linked to Technical or Funding Realities

The initial baselines for 8 of the 10 major projects we reviewed contained schedules that were influenced by an EM-wide effort to accelerate the office's cleanup work. In 2002, EM management worked with its sites and regulators to create new, earlier milestones for completing key cleanup projects and for closing entire sites to reduce the public health and environmental risks posed by the waste at these sites. Before this effort, some of the major cleanup projects were not estimated to complete work until the 2030s and 2040s. Under the accelerated schedules, four projects'

completion dates were moved up by 15 years or more, as was the case for the radioactive liquid tank waste stabilization and disposition project at the Hanford site; its completion date was moved from 2048 to 2028. The baselines containing the accelerated schedules—those generally created between 2003 and 2006—tied their work scope and funding assumptions to the completion dates and not necessarily to available cleanup technologies. For example:

- *Solid waste stabilization and disposition project at Idaho*. To meet its accelerated completion date of 2012—down from 2018—DOE's Idaho National Laboratory assumed its Advanced Mixed Waste Treatment Plant could process nuclear waste at a rate of about 8,500 cubic meters per year—more than 50 percent faster than the rate of about 5,400 cubic meters per year demonstrated when DOE established the baseline. At the time, because the plant had only recently begun operating, project staff lacked confidence that they could meet the processing rate. Moreover, the independent team reviewing the baseline reported that the rate was optimistically high. Nevertheless, DOE proceeded with the initial baseline, increasing the amount of unfunded contingency in its baseline and attempting to meet the optimistic rate by providing the contractor with performance incentives. Still, the processing rate has fallen short of baseline assumptions—it is currently roughly 6,000 cubic meters per year. To reflect this more realistic rate, DOE subsequently revised its baseline, adding 4 years to the project schedule and increasing costs by about $450 million.

- *Radioactive liquid tank waste stabilization and disposition project at Savannah River*. This project, in part, combines high-level radioactive waste stored in tanks at the Savannah River Site with melted glass and places it in canisters ultimately to be sent to a federal repository for disposal. DOE directed that the project's completion date be accelerated, from 2035 in its early planning documents to 2019 in the initial baseline. In order to make that date, according to project officials, they included some assumptions in the initial baseline they knew at the time would be difficult to realize. Specifically, they assumed that the project's waste processing facility could produce canisters consisting of up to 49 percent high-level waste—with the remaining space filled with melted glass—when at the time it had not been able to produce a canister containing more than 42 percent high-level waste with an existing technology while remaining within the acceptance criteria for the federal repository. Those criteria dictate specific characteristics, including durability and leachability for the glass-waste mixtures in the canisters. DOE has since adjusted these assumptions—the current waste processing plan assumes the canisters will contain 34 percent to 38 percent high-level waste using the existing

technology—contributing to the overall cost increase and schedule delay for this project.

These early baselines also were not tied to expected funding. According to several senior EM officials, before April 2007, project directors were instructed to create cost baselines to meet the accelerated schedules and their regulatory milestones without regard for the likely funding the projects could expect to receive. Consequently, the funding assumptions in the projects' baselines were higher than the amount of funding DOE requested each year. According to a senior EM budget official, these shortfalls required project managers to continually adjust cost and schedule baselines as projects moved work activities into the out years to accommodate the lower funding levels. For example, according to site officials at Oak Ridge, when DOE did not request the full amount of funding in the nuclear facility's decontamination and decommission project's initial baseline, the project could not complete all the work as planned. Project managers responded by pushing work activities into the out years, which contributed, in part, to the project's overall cost increase and schedule delay. Similarly, as noted in a recent DOE internal audit, according to Los Alamos officials, funding has not been sufficient to meet the site's regulatory commitments, and has been a concern since 2003, when the site manager said he was concerned that appropriate resources had not been identified to conduct the necessary environmental restoration activities.[17]

According to EM managers, they have implemented changes to the way baselines are created that address these problems. In April 2007, EM changed its policy for creating project baselines. Instead of tying baselines to the accelerated schedules and regulatory commitments with unconstrained funding, EM limited funding for its sites, directing that all future baselines be based on expected budget numbers generated for each site.

For three of the projects we reviewed, this change in direction resulted in deferral of work and schedule delays because the new funding levels represented significant reductions in what projects were planning on

[17]U.S. Department of Energy, Office of Inspector General, Office of Audit Services, *Audit Report: The Department's Progress in Meeting Los Alamos National Laboratory Consent Order Milestones*, DOE/IG-0793, April 2008.

receiving, and these projects were low on EM's priority list.[18] For example, Hanford's solid waste stabilization and disposition project's funding was reduced to the point where it will receive minimal funding for the next 4 years in order to allow full funding of Hanford's decontamination and decommissioning project at River Corridor, a higher priority. During this period, to comply with the funding levels provided, the project will maintain minimum activities to safeguard materials and will not advance its waste processing goals. As a result, according to project officials, life cycle costs for this project increased in some part to reflect a longer schedule and the additional costs of having to hire and train new workers in the future to complete a job that already was underway.

Not all sites have implemented these changes, however. EM's direction to all sites to create their baselines tied to the funding profile outlined in the June 2007 policy memo has not been applied to two of the major cleanup projects. The Hanford radioactive liquid tank waste stabilization and disposition project—the most expensive cleanup project—and the Los Alamos soil and water remediation project have not aligned their baselines with the funding targets. The Hanford project's baseline was validated just before the policy change took place and, for the period between 2009 and 2030, the baseline contains about $2.6 billion more than the funding targets.[19] Similarly, EM approved the baseline for the Los Alamos project even though it was not aligned with the funding targets. The baseline identifies a projected funding shortfall each year through 2012 that peaks at a cumulative $236 million in 2010. This shortfall does not include an additional $947 million in unfunded contingency. At the same time EM approved the baseline, it directed project managers at the site to change the baseline to bring its costs in line with the targets.

Another likely contributing factor to the cleanup projects' cost increases and extended schedules is DOE's practice of not including contingency funding in its annual budget requests for EM's cleanup projects. Specifically, EM has requested enough funding for its cleanup projects to ensure a 50 percent likelihood of completing the projects within the total estimated project costs. However, the requested amount generally has not

[18]EM's priority list is based on maximizing risk reduction. As such, it has ranked its activities in priority order, from highest to lowest, from stabilizing radioactive tank waste in preparation for treatment down to decontaminating and decommissioning excess facilities.

[19]Figures in this paragraph are in current year dollars.

included contingency funding, which project managers may have to use in order to complete a project on time by addressing risks that materialize during cleanup. For example, in 2007, the radioactive liquid tank waste project at Hanford had an unexpected spill of 85 gallons of radioactive material from one of its storage tanks; this spill required shutting down waste retrieval operations for 11 months in order to clean up the spill. Even though the retrieval operations represent a small percentage of the overall work scope ongoing at the project, the accident added at least $8 million to the retrieval cost for that one tank. Furthermore, in accordance with EM policy, projects are expected to account for the costs of such potential risks by increasing the amount of unfunded contingency in their near-term and life cycle baselines. Because funding for that contingency is not included in the budget request, however, increasing the amount of contingency funding in the near-term baseline is largely a paperwork exercise that has no active impact on preventing or solving problems or anticipating actions that could offset demonstrated slow progress.

According to a December 2007 report by the National Academy of Public Administration, EM's practice of not funding contingency for its cleanup projects has meant that EM has not had additional funding available to address emergency problems when they arise and therefore has either taken money from another project or extended the schedule of the work into future fiscal years to manage them. Furthermore, according to EM officials, by providing enough funding for its projects to ensure that they have a 50 percent chance of meeting their project cost and schedule baselines, EM recognizes that 5 of the 10 major projects are likely to miss their cost and schedule goals. In contrast, DOE funds its construction projects at a level that reflects a greater probability of success—80 percent—an amount that reflects the industry standard for such projects. According to senior EM officials, EM does not fund contingency for its cleanup projects because allotting enough funds to cover the costs of risks that may not materialize would constrain the amount of work EM could perform for the money it receives each year. However, in accordance with a recommendation from the National Academy of Public Administration, EM is evaluating its practice of not including contingency funding in its budget requests for cleanup projects.

Baselines Included Assumptions about the Scope of Work and Technical Challenges That Did Not Hold True

For most of the projects we reviewed, EM included assumptions in its baselines that (1) did not represent the conditions at some of the major projects, (2) did not sufficiently anticipate delays in the completion of related construction projects, and (3) the scope of work activities to be accomplished would not increase. Correcting these assumptions often led to changes in the scope of work, higher costs, and extended schedules.

First, for four of the projects we reviewed—Oak Ridge's nuclear facility decontamination and decommissioning project, Idaho's solid waste stabilization and disposition project, and Savannah River and Hanford's radioactive liquid tank waste stabilization and disposition projects—site conditions were worse than project staff originally estimated, leading to significant changes to the life cycle baseline.[20] For example, at the Oak Ridge project, because a 1940s-era building was far more contaminated and deteriorated than first estimated, DOE changed its cleanup plan and implemented a more extensive—and therefore more expensive—approach to tearing down the building. After a worker fell through a weakened floor, the contractor had to first reinforce the building's structure so that contaminated equipment could be removed safely. Primarily because project officials did not accurately anticipate the site conditions or the types of work activities necessary to safely conduct the work—despite multiple estimates generated by the contractor, DOE, and the Army Corps—this project's costs increased by $1.2 billion and significant amounts of work were delayed, extending the completion date by 9 years, to 2017.

Similarly, the initial baseline for the radioactive liquid tank waste stabilization and disposition project at Hanford assumed that 99 percent of the waste contained in the 177 storage tanks could be removed by using only one type of technology to retrieve the tank waste. However, DOE subsequently determined that almost half of the tanks contained a hardened layer of waste that could not be removed with the chosen technology and therefore a second technology was needed to remove this waste. Correcting the optimistic assumptions—adding the second technology and re-estimating the costs of retrieving waste from the tanks based on field experience gained—increased the baseline by more than $2 billion.

Second, delays in completing related construction projects directly contributed to schedule delays—and corresponding cost increases—for four of the cleanup projects we reviewed. Three of these projects are at the Hanford site in Richland, Washington. The initial baselines for these projects included assumptions that the major construction project there—the Waste Treatment Plant (WTP)—would be ready to begin operations in

[20]According to project officials, site conditions also were worse than estimated at Hanford's nuclear facilities decontamination and decommissioning project at River Corridor, although a baseline change proposal for the cost increase for this project had not been filed with EM headquarters at time of our review.

2011. In 2006, DOE extended the WTP construction completion date by 5 years, resulting in schedule extensions for three cleanup projects.[21] The major cleanup project that will run the WTP—the radioactive liquid tank waste stabilization and disposition project—had to increase its life cycle cost estimate by about $4.8 billion and extend its schedule by 10 years in order to safely maintain the waste storage tanks while the treatment plant is being built and to operate the plant for additional years, among other things. Similarly, in response to the WTP delay, the schedules for the solid waste stabilization and disposition project and the soil and water remediation project were extended by 15 years—increasing costs by more than $4 billion combined. These projects cannot complete their missions until the WTP has finished processing all of the liquid waste in the storage tanks. According to the currently approved baselines, the liquid tank waste project will complete its operations in 2042, and activities under the latter two projects are not expected to be completed until 2050.[22] However, as we recently reported, DOE has acknowledged that the start of waste treatment operations will be delayed by at least 8 years (from 2011 to 2019), not 5 years, which will likely affect further these projects' costs and schedules.[23]

Third, for three of the projects we reviewed, increases in work scope—the activities required to complete the project—contributed to cost increases and schedule delays. For example, a major contributor to the more than $3 billion cost increase and at least 9-year schedule delay at the nuclear materials stabilization and disposition project at Savannah River was DOE's approval of a new initiative in 2006 that added additional amounts of nuclear materials for the project's facilities to disposition, including materials from other DOE sites. Those facilities were originally scheduled to complete their mission in 2007—the new scope extended the mission

[21]In 2006 we reported on the primary causes of the cost and schedule increases at the WTP, some of which echo the issues we found relative to the major cleanup projects: shortcomings in the contractor's performance, DOE management and oversight problems, and technical challenges that were more difficult to address than anticipated. GAO, *Hanford Waste Treatment Plant: Contractor and DOE Management Problems Have Lead to Higher Costs, Construction Delays, and Safety Concerns*, GAO-06-602T (Washington, D.C.: Apr. 6, 2006).

[22]These dates are based on a 50 percent confidence level. With 80 percent confidence, the liquid tank waste is estimated to extend until 2050, the solid waste project is estimated to complete in 2058, and the soil and water project is estimated to extend until 2059.

[23]GAO, *Nuclear Waste: DOE Lacks Critical Information Needed to Assess its Tank Management Strategy at Hanford*, GAO-08-793 (Washington, D.C.: June 30, 2008.)

until 2019.[24] Similarly, Savannah River's other major cleanup project—radioactive liquid tank waste stabilization and disposition—also had significant scope added. Under a law passed in 2004,[25] DOE determined that the salt waste in its tanks is not high-level waste and therefore can be disposed of at the site instead of in a geologic repository. The law required DOE to consult with the Nuclear Regulatory Commission when making this determination. According to DOE, this consultation and the resulting changes to the cleanup process added significant scope to the project, causing DOE to lengthen the estimated time to close the 49 tanks at the site.

According to EM, most of the cost increases and schedule delays experienced by the major cleanup projects were the direct result of unrealized aggressive planning assumptions. EM has since recognized that project baselines must be based on realistic technical and regulatory assumptions and be planned on the basis of realistic out year budget profiles. However, it appears that the practice of incorporating optimistic assumptions into project baselines has not yet been eliminated. As we recently reported, some of the underlying assumptions in the baseline for the Hanford radioactive liquid tank waste project may be overly optimistic.[26] For example, DOE assumes that the tanks will remain viable throughout what has become a protracted waste treatment process, with some tanks expected to remain in service more than 60 years longer than originally anticipated. This extended operation raises the risk of tank failure and leaks to the environment. The baseline also assumes that emptying single-shell tanks will proceed significantly faster than it has to date. Hanford project management officials have since acknowledged that the ambitious retrieval schedule might not be achievable and are adjusting their planning estimates.

[24]As we recently reported, DOE may identify additional nuclear materials to process through these facilities, which could delay the planned 2019 shutdown and increase operational costs. GAO, *Nuclear Material: DOE Needs to Take Action to Reduce Risks Before Processing Additional Nuclear Material at the Savannah River Site's H-Canyon*, GAO-08-840 (Washington, D.C.: July 25, 2008).

[25]Ronald Reagan National Defense Authorization Act for Fiscal Year 2005, Pub. L. No. 108-375 § 3116. This law resolved a lawsuit in which an environmental group alleged that DOE lacked authority to determine that particular wastes were not high-level waste.

[26]GAO-08-793.

DOE Has Not Effectively Used Available Management Tools to Help Control Major Cleanup Projects' Scope of Work, Costs, and Schedule

While DOE has several mechanisms in place to help manage cleanup projects, including independent reviews, performance information systems, guidance, and performance goals, it has not always used them to effectively manage major cleanup projects' scopes, costs, and schedules.

DOE's Baseline Reviews Highlight Problems but Have Not Succeeded in Ensuring Work Can Be Accomplished within Stated Cost and Schedule

OECM's independent reviews of the baselines, meant, among other things, to provide reasonable assurance that the project's work activities can be accomplished within the stated cost and schedule, have not done so for four of the projects we reviewed. Instead, these baselines were significantly modified shortly after approval. As a result, the usefulness of the independent baseline reviews is questionable when significant baseline changes occur very shortly after the reviews are completed, as the following discussion illustrates.

The advanced mixed waste treatment project under Idaho's solid waste stabilization and disposition project. OECM's 2006 independent review accurately noted that the project baseline submitted for validation for the treatment plant included an unrealistic rate for processing waste—more than 50 percent faster than the rate demonstrated at the time the baseline was established. In response, project officials proposed correcting the problem primarily by increasing the amount of unfunded contingency in the baseline, a move that reflected common practice within EM, and OECM officials approved this action and validated the baseline. As the panel predicted, the project's actual processing rate after its baseline was validated was slower than expected. Within 7 months of OECM's validation of the near-term baseline, project officials proposed modifying it. DOE had to defer the activities that the contractor was not able to accomplish in the near term, extending the project life cycle by about 4 years and increasing costs by about $450 million. We believe that DOE's approval of increasing unfunded contingency as a corrective action for an

unrealistic processing rate was ineffective.[27] Although DOE also attempted to increase the processing rates through contractor performance incentives, we believe DOE should have revised the baseline using a more realistic processing rate to calculate baseline cost and schedule before validating it.

Oak Ridge's nuclear facility decontamination and decommissioning project. Significant cost increases began 2 years before OECM's independent validation of the project in 2006, and have continued to increase. Specifically, life cycle costs for the project were estimated at $1.8 billion in 2004—the beginning of the project's previous near-term baseline—with expected project completion by fiscal year 2008. By August 2006, when OECM completed its review of the baseline and issued its validation recommendation, life cycle costs for the project had grown to about $2.2 billion and project completion was extended by about 1 year. However, roughly 1 year after OECM validated the baseline, EM revised it again, adding about $800 million in costs and delaying project completion by an additional 8 years. EM justified the change because, among other things, it wanted to adjust the baseline to conform to new funding targets as directed by DOE in June 2007 and to account for other changes it needed to make in its approach to decontaminating the building.

Los Alamos soil and water remediation project. In March 2008, EM approved an independent review of this project and the associated baseline although it expected that the baseline would change. According to the EM memorandum approving the baseline, changes in EM's priorities and funding plans were likely to necessitate changes to the Los Alamos project's baseline, and the project was directed to submit a baseline change that would align the baseline with funding targets. OECM officials also acknowledged that their independent review of the baseline was based on assumptions that would likely not prove to be true. Specifically, OECM's review assumed that the project would receive the full funding needed even though DOE's funding targets at the time were below the funding levels needed to comply with the state cleanup agreement. As a result, project officials expect that the estimated life cycle costs of nearly $1.7 billion will increase substantially during 2008 but could not tell us the

[27]DOE included $180 million (representing an additional 18 months of work) in its unfunded contingency for this project , which would have covered only part of the $450 million cost increase or the 4-year schedule delay experienced by the project.

extent of the cost and schedule change until they receive DOE's new funding commitments for the project.

Hanford's radioactive liquid tank waste stabilization and disposition project. The most significant cost increase—more than $9 billion—occurred about 2 years after DOE's initial independent review and approval of this project. The project's baseline was first approved in 2004, with life cycle costs expected to be about $22 billion and completion scheduled for 2032. However, in 2006, life cycle costs increased to about $31 billion—not including an additional $8.6 billion in unfunded contingency—and the completion date was extended by 10 years, to 2042. Project officials expect the baseline will require another update and independent review in 2009 to reflect anticipated changes as a result of the project's new contractor and because of changes resulting from ongoing negotiations with state regulators over regulatory agreement milestones.

In addition to changes to the baselines soon after the independent reviews, DOE has recently relaxed standards used for conducting these reviews. In 2003, DOE issued standard operating procedures for conducting independent reviews—primarily of construction projects. These procedures stated that baselines should be considered, once approved, as set in concrete. The EM-OECM 2005 protocol—and its 2007 update—for cleanup projects replaced the standard operating procedures and directed OECM to validate only the near-term baseline for cleanup projects while reviewing the life cycle estimate "for reasonableness." In this way, EM and OECM sought to acknowledge what they believe are the greater uncertainties present in the out-years of a cleanup project compared with a typical construction project. However, within a year of the 2007 protocol, OECM had changed its approach for EM cleanup projects from validating baselines to "certifying" them, which is a more limited statement of assurance than validation. Specifically, according to OECM officials, certification means that the near-term baselines are reasonable if near-term baseline costs are funded as outlined in the baseline and contingency funds are provided as needed. The change is intended to reflect OECM's belief that, because funding for cleanup projects is more uncertain than for construction projects, the same confidence level cannot, nor should, be applied to reviews of EM cleanup project baselines as it is applied to construction projects. Since EM headquarters does not consistently provide contingency funds for its cleanup projects, and half of the major projects have significant contingencies in their near-term baselines, the most likely result for projects experiencing problems is to extend schedules and increase life cycle costs. In commenting on a draft of this report, OECM stated it intends to go back to validating near-term baselines

for cleanup projects, assuming, in part, that funding becomes more stable and EM gains greater experience managing near-term baselines.

DOE Lacks Reliable and Consistent Performance Information

DOE managers depend on data about the performance of EM's major cleanup projects to make informed decisions about how best to handle unexpected events and manage shifting priorities. DOE site and headquarters staff generate a number of regular reports to update senior managers on the status of these projects, both to justify making significant changes to project baselines and to request funding from Congress. Although these reports provide valuable information to managers on the progress of work at cleanup sites around the country, they do not consistently provide the key information needed to make fully informed management decisions about EM's major cleanup projects. Specifically, (1) proposals for baseline changes do not consistently identify reasons for proposed changes or possible root causes that contributed to problems, (2) use of EVM data does not consistently conform to industry standards or GAO's best practices, (3) quarterly reports do not always describe the impact of contractor performance on near-term or life cycle costs and schedules, and (4) reports to Congress on the status of and changes to major cleanup projects are limited to a small snapshot in time and do not provide information necessary for effective oversight.

EM Baseline Change Reports Do Not Consistently Include Needed Information

When a project reaches a point at which it is likely to miss the goals in its baseline, project managers are required to propose changes to the project's cost, schedule, or scope baseline, a process that is akin to hitting the reset button. EM project managers request such a change by, among other things, documenting certain information in a Baseline Change Proposal report, including current approved costs and new proposed costs, proposed project start and end dates, and a justification for the changes. For the key change proposals we reviewed for the major cleanup projects, the information provided describing the changes and their impacts varied widely, with some projects providing little to no explanatory information about what led to the change and others explaining the causes of the changes in detail. For example, a change proposal for Hanford's nuclear material stabilization and disposition project simply described the project's scope of work and did not provide any explanation for why the project's schedule was being delayed by 3 years, while a proposal from Savannah River's radioactive liquid tank waste stabilization and disposition project included information on the causes for its cost and schedule changes, as well as the specific cost and schedule impacts of each cause. However, the change proposals we reviewed generally did not address the root causes that resulted in the changes to the baseline. For example, the Savannah River change proposal

explained that almost $500 million of the total proposed cost increase was due to revising the strategy for finishing the project. However, the proposal did not explain why this strategy needed revision. In investigating the reason for this proposed revision, we determined that a robust strategy for finishing the project was not included in the original baseline because the project was directed to meet a completion date of 2025 and could not do so if it included the thorough closure strategy. Without including this kind of information in the proposals, it would be difficult for EM managers to effectively identify the true causes of the baseline changes, take steps to address them, and transfer any lessons learned to other projects.

In addition, EM does not centrally gather and systematically analyze the narrative information in the baseline change proposals. We recognize that such information is not easily analyzed to identify common causes across projects. However, without such analysis, EM senior managers are potentially hindered in addressing problems collectively. One EM project management official agreed that having the ability to analyze the information in the change proposals across projects would be beneficial, but that his office had not yet made it a priority to collect this information because it was still addressing reliability issues with the data in the change proposals.

EM has made some effort to identify root causes of its project management problems. It recently participated in a DOE-wide effort to identify root causes of project and contract management problems in response to GAO's inclusion of DOE's contract management on its high-risk list.[28] However, DOE's analysis was focused more on construction projects than EM cleanup projects. The report notes that the emphasis of the effort was on the capital line item—construction—projects, but that several of the issues identified also are applicable to other projects, including EM cleanup projects.[29] According to one project participant from OECM, the participants discussed how some of the issues raised related to cleanup projects but they did not examine those projects as extensively as the construction projects. In commenting on a draft of this report, DOE explained that its analysis was based more on data from construction projects than EM cleanup projects because more data exist documenting DOE's past project management deficiencies for construction projects

[28]GAO, *High-Risk Series: An Update*, GAO-07-310 (Washington, D.C.: January 2007).

[29]DOE, *Root Cause Analysis: Contract and Project Management* (Washington, D.C., April 2008).

since those projects have a longer history of a structured, disciplined management process.

Use of Earned Value Data Does Not Always Conform to Industry Standards or GAO-Identified Best Practices

At three of the major cleanup projects—nuclear facilities cleanup at the Hanford Site's river corridor cleanup project, solid waste stabilization and disposition at Idaho National Laboratory, and soil and water remediation at Los Alamos National Laboratory—we found several instances in which the use of EVM data did not conform to industry standards or our best practices.[30] As a result, EM and site project managers using the data may be less able to make informed decisions to effectively manage these projects.

Data anomalies. For all three projects, the EVM systems we assessed contained data errors or anomalies that could potentially distort the analysis of EVM data. Anomalies included, for example, reporting negative actual costs or reporting costs that are not tied to work scheduled or performed. The Los Alamos EVM data contained both types of these anomalies, which may have distorted the results of data analyses by as much as $34 million, preventing managers from understanding the true status of project performance. According to project officials, the anomalies occurred primarily because Los Alamos had initially assigned costs to a general account, and waited up to several months before assigning these costs to the correct specific work activities. In another case, in a significant number of instances the contractor at Hanford's river corridor closure project reported costs incurred for work activities performed that had not been scheduled to start until future years, skewing the reported performance results.[31] The contractor explained that these data anomalies occurred because it had performed work sooner than originally expected—and therefore the work was not incorporated into the project's EVM planned schedule in the periods for which it was actually performed. Project officials at the site stated that they believe the EVM information, as reported, correctly represents the project's status. As such, the summary-level EVM data seem to depict a favorable schedule

[30]We conducted limited assessments of EVM data reliability, compliance with industry standards or our best practices, and other analyses at three of the five EM sites we visited, including data from the Hanford site's river corridor cleanup project, Washington; Idaho National Laboratory's advanced mixed waste treatment plant subproject (within the solid waste stabilization and disposition project), Idaho; and Los Alamos National Laboratory's soil and water remediation project, New Mexico.

[31]Specifically, we found elements where the contractor reported budgeted and actual costs of work performed without a corresponding work schedule.

performance in April 2008; however, our independent analysis of this data shows that when we removed the value of the work that was started and completed ahead of schedule, the remainder of the originally scheduled work was actually behind schedule in April 2008, and trends indicated that the variance was worsening.

Data on the availability of staff to perform future work was not always developed. For one of the projects we reviewed, the EVM system lacked important information on staffing, contrary to GAO-identified best practices. DOE officials at Los Alamos' soil and water remediation project told us they plan to begin asking for staffing information from the contractor, and contractor officials stated they are setting up a staffing report within their EVM system. Without this information, project managers lack important information necessary for ensuring that they have, or will have, an adequate number and type of staff to perform the upcoming scheduled work.

Reliability of earned value systems is questionable. OECM has certified that the earned value system used to report performance for only one of the three systems we assessed meets the required industry standards.[32] The EVM system used by the contractor operating the advanced mixed waste treatment project—a significant portion of the solid waste stabilization and disposition project at the Idaho National Laboratory—has not been reviewed by OECM to determine whether it is compliant with industry standards, and contractor officials stated they believed their system does not meet the standards. In addition, OECM was in the process of reviewing the system used by the contractor responsible for the soil and water remediation project at Los Alamos National Laboratory at the time of our review. As a result, these projects lack the necessary assurances that the EVM data were free of errors and anomalies that could skew and distort the EVM analyses.

Once a system is certified as meeting the standards, regular surveillance is needed in order to ensure its continued compliance. Surveillance allows managers to focus on how well a contractor is using its EVM system to manage cost, schedule, and technical performance, and is important

[32]OECM has certified that all of the EVM systems used by the contractors working on the 10 major cleanup projects are in compliance with the American National Standards Institute/Electronic Industries Alliance standard except that of the Advanced Mixed Waste Treatment Project contractor at Idaho and the major project at the Los Alamos National Laboratory.

because it monitors problems with performance and the EVM data. If these kinds of problems go undetected, EVM data may be distorted and not meaningful for decision making. OECM's surveillance program is under development: it recently hired one staff person to lead its surveillance efforts, and is developing a guide to better define its surveillance protocol. DOE also requires its sites to perform surveillance of EVM monthly contractor performance data, which includes developing EVM surveillance plans and conducting random EVM surveillance.

Furthermore, EM managers do not appear to consistently gather or analyze EVM data to maximize the data's benefits for project management. GAO best practices recommend that EVM system reports include thorough narrative explanations of any root causes of, or proposed corrective actions, for reported cost and schedule variances shown in the data. For the soil and water remediation project at Los Alamos, for example, EM did not require that this information be reported by its contractor. As a result, EM project managers at Los Alamos have not always received the information necessary for ensuring that effective corrective actions are implemented to prevent additional changes to the cost and schedule baselines. According to contractor officials, they reported information on root causes and corrective actions to EM routinely before fiscal year 2008, but DOE asked them to stop providing it. According to the project director for the soil and water remediation project at Los Alamos, the Los Alamos Site Office Assistant Manager had directed the contractor to not provide the variance reports as part of its project status reviews because the contractor's explanation of these variance reports during scheduled meetings was taking several hours to review and wanted instead to use the available time to focus more on risk management and other project issues. However, according to this site official, the site office's direction was not intended to discontinue all variance analysis reporting. Although the contractor discontinued including the variance analyses reports in its project status reviews, the project director stated that DOE continues to obtain information from the contractor by other means, such as cost performance reports and weekly contractor meetings at which DOE and the contractor discuss the root causes of variances that resulted in risks to meeting milestone compliance agreements. However, contractor cost performance reports we reviewed did not provide any narrative information on causes or corrective actions. Furthermore, the weekly contractor meetings discuss only certain root causes of the variances that resulted in risks to milestone compliance agreements and therefore are neither comprehensive nor documented. Because verbal information can easily be forgotten, lost, or misinterpreted, among other things, we believe that a written report would be a best practice.

In addition, EM projects report their EVM data to headquarters managers at the project summary level, which can mask problems occurring in the project that more detailed reporting could reveal. At Idaho, in early 2008, EVM data showed the solid waste stabilization and disposition project was performing ahead of schedule and under cost, although major problems had occurred at the advanced mixed waste treatment project—the primary subproject. Without EVM reports that contain more specific detail, project managers at headquarters may not recognize that a problem is occurring until it becomes large enough to recognize at the summary project level of reporting. In addition, greater detailed information provided to managers earlier in the project potentially could allow for early intervention.

Beyond more detailed reports, some project managers in the field and at headquarters have not always systematically reviewed or independently analyzed the EVM data they received, which also would help improve their understanding, as well as mitigate potential problems occurring within a project. At one site we visited, the DOE official receiving the data said he did not analyze the information before entering it into the EM headquarters database. In turn, headquarters EM project managers told us they also do not analyze the EVM data the projects report. One oversight official indicated he would prefer to analyze the information he receives from the projects but he did not have the time required to do so. A senior EM project management official told us that he recognizes this deficiency and is working to address it: EM intends to pilot a new software package that will allow managers to analyze EVM data. According to EM, the software will enable EM managers to drill down into the EVM data received from the contractors, thus improving their oversight capabilities. In addition, according to EM project management officials, EM has insufficient federal staff to conduct oversight, which is being addressed as part of an ongoing effort to improve project management. In commenting on a draft of this report, EM stated it also intends to provide additional EVM training for its analysts.

Quarterly Reports Do Not Present a Comprehensive Picture of Performance against Near-Term or Life Cycle Commitments

In accordance with Order 413, EM senior managers, including the Assistant Secretary, receive quarterly updates on the status of the major cleanup projects. Two key reports are the quarterly project reviews (QPR), generated by EM project managers, and a quarterly project status report created by OECM. These reports contain contractor performance data and information about new or ongoing issues that need addressing at the sites, but do not always describe how contractor performance affects performance against the near-term or life cycle baselines. Without this information, managers cannot develop a comprehensive assessment of progress against agreed-upon goals.

The QPRs and OECM quarterly reports we reviewed largely use EVM data to assess project performance, but these data only reflect performance against the current contract period. Current contract period start and end dates do not line up with the start and end dates of the near-term baselines for any of the major cleanup projects we reviewed, and contract goals have not always been tied to what would be necessary to meet near-term baseline goals.[33] For example, we found the EVM data for Idaho's solid waste stabilization and disposition project—including the advanced mixed waste treatment subproject—that was reported in the QPRs and OECM quarterly reports from early 2008 did not line up with the near-term baseline because the advanced mixed waste treatment project's contract period was not the same as the near-term baseline period, which ends in 2012. EVM data for this project are reported as a combination of work done by two contractors: disposal of low-level and mixed-low-level waste, among other things, by the major site contractor, whose contract runs through 2012, and the advanced mixed waste treatment project operations contractor, who, in early 2008, was operating under a contract extension that expired in April 2008, 4 years shy of the end of the near-term baseline. In addition, according to project officials, the goal of processing 15,500 cubic meters of waste contained in that contract extension was not based on what was necessary to meet the near-term baseline goal of processing 65,000 cubic meters of waste by 2012, which was DOE's commitment at the time of the extension. Since the advanced mixed waste treatment project's activities make up about 75 percent of the cost baseline for the overall project, EVM data for this project as reported in the QPRs and OECM quarterly reports were not an accurate indicator of how the project was performing against the approved near-term baseline. DOE has further extended the advanced mixed waste treatment project contract through September 2009, and project officials explained the current extension is better linked to the current baseline, meaning EVM data reported should represent a better indication of performance against that baseline.

In addition, although the QPRs we reviewed include data on current life cycle cost and schedule estimates, they do not always include information about changes to the schedule or scope, nor do they explicitly mention when a change to the baseline has been proposed. Instead, the QPRs generally present information on life cycle cost increases and provide

[33]Contract start and end dates for the major cleanup projects do not match near-term baseline start and end dates. Furthermore, EVM data at Los Alamos is reported only against the current fiscal year, not against the full contract period or the near-term baseline.

comparisons to original baselines. QPRs also contain a schedule for each project detailing key milestones and expected end dates. However, when a change to a project completion date is made, the schedule shown in the QPR in most cases does not preserve the original completion date as a point of comparison. Similarly, there does not appear to be any mechanism in the QPR to present a change in a project's scope of work, for example, a move of some work activities from the near term into the out years. As a result, the reports tell only that life cycle costs have increased, but corresponding changes to schedule and scope are not apparent. Furthermore, there is no clear place in a QPR for a project manager to mention that a baseline change proposal has been submitted to headquarters if the results of that proposal are not yet presented in the life cycle cost or schedule information in the report. Including mentions of pending change proposals may help ensure senior managers clearly understand the true state of a project's performance.

A key performance indicator used in OECM's quarterly reports also may create the impression that a project is performing well overall when it is in fact encountering problems. As directed in the 2007 protocol for cleanup projects, OECM uses a traffic light indicator—red-yellow-green—as an at-a-glance way to highlight developing problems for DOE managers. This indicator is intended to represent expected performance against the approved near-term baseline and is based largely on EVM data. However, since projects encountering problems tend to manage those problems by moving work scope into the out years, the effects of problems occurring today show up as increases to out-year cost and schedule estimates and not as increases or delays in a near-term baseline.[34] Therefore, a project rated "green" by OECM may simultaneously be experiencing increases in overall life cycle costs and delays in project completion. OECM officials agreed that it would be beneficial to present projected impacts of current performance on life cycle estimates wherever practical in its reports.

EM Does Not Report Information about Significant Changes to Near-Term and Life Cycle Baselines to Congress

DOE's reports to Congress do not include key information that would aid oversight efforts, including the extent of and reasons for significant changes to near-term and life cycle baseline estimates, and the status of estimated life cycle costs. DOE's annual budget request to Congress for fiscal year 2009 for EM included funding requests for each site and each project, as well as the funding appropriated in fiscal years 2007 and 2008.

[34]In commenting on a draft of this report, EM indicated that scope deferrals or changes to the near-term baseline must now be formally approved by EM management.

The budget request also contains, among other things, descriptive information about the sites and projects, including EM's major cleanup projects, and about cleanup goals, regulatory frameworks, and key uncertainties. However, the request did not provide any project-specific life cycle costs or completion dates.[35] In the previous three budget requests, EM had provided life cycle costs and planned completion dates for each project. Without this information, Congress cannot know what progress each project has made and the extent of work still needed, cannot understand how the project may be changing and has changed over time, and cannot know whether the project experienced problems since the previous budget request and the reasons for these problems. The absence of this information makes it more challenging to effectively oversee the department and its major cleanup projects.

DOE has not been directed to provide such information about its major cleanup projects to Congress. In contrast, Congress has required the Department of Defense to report annually on its major defense acquisition programs—those costing $2 billion or more and typically consisting of a weapons system, such as Navy ships or fighter planes—or report quarterly when programs are experiencing significant cost increases or schedule delays.[36] Congress established the reporting requirement to improve oversight of these defense programs by providing visibility and accountability for any growth in cost that may occur. Known as Selected Acquisition Reports, each annual report includes information on full life cycle program costs, unit costs—the cost per plane or ship—and the history of those costs. A quarterly report also includes reasons for any change in unit cost or program schedule since the previous report, information about major contracts under the program and reasons for any cost or schedule variances, and program highlights. In addition, the Department of Defense includes development and procurement schedules, with estimated costs through program completion, in its annual budget justification submissions to Congress.

[35]DOE's fiscal year 2009 request for EM includes ranges of life cycle costs and completion dates at the site level.

[36]Major defense acquisition programs are those identified by the Department of Defense that require eventual total research, development, test, and evaluation expenditures of more than $365 million or $2.19 billion for procurement in fiscal year 2000 constant dollars.

DOE Guidance for Management and Oversight Functions Is Unclear and Not Implemented Uniformly across Sites

EM's key policies for managing its cleanup projects—including developing project baselines, managing risk, and planning for contingency funding—are not consolidated but spread across various guidance documents and memos and provide contradictory and confusing information. Although Order 413 serves as the overarching policy document for project management, according to EM, the order contains requirements that are unnecessary or expensive and awkward to implement for cleanup projects. EM thus has issued numerous memos outlining the way in which its project managers should implement the order. See table 3 for a list of key memos we identified that contribute to project management guidance and policy for EM cleanup projects.

Table 3: Key Policy Memos for EM Cleanup Projects

Date	Title	Source	Guidance provided
February 3, 2005	EM Contingency Policy	EM	Policy on funding contingency and preferred method for establishing contingency
June 23, 2005	Project Management for the Acquisition of Capital Assets—DOE Manual 413.3-1	DOE Office of Management, Budget and Evaluation	Requirements and guidance on implementing Order 413
July 10, 2006	Policies for EM Operating Project Performance Baselines, Contingency and Federal Risk Management Plans, and Configuration Control[a]	EM	Additional clarification and guidance on process and requirements to identify, develop, control, and validate EM baselines
July 28, 2006	Program and Project Management for the Acquisition of Capital Assets—DOE Order 413.3A	DOE	Project management guidance on acquisition of capital assets and environmental restoration projects
March 2, 2007	Risk Management Policy	EM	Statement of EM risk management policy
April 24, 2007	Protocol for EM Cleanup Project Performance Baselines and Conducting the External Independent Review or the EM Independent Project Review	EM and OECM	Governs review and validation of cleanup projects
June 25, 2007	Guidance for Implementing Baseline Changes to Reflect Funding Targets for Fiscal Year 2008 through the Out-Years	EM	Directed sites to develop baselines tied to specific funding targets provided
February 13, 2008	Configuration Control Process for Project Baselines	EM	Update on EM effort to put baseline under configuration control

Source: GAO's analysis of DOE information.

[a]Configuration control refers to efforts to manage and track any changes to work activities, costs, and schedules.

As the table shows, rather than having a consolidated source for guidance, EM project managers must consult multiple sources to determine how to correctly create a baseline or calculate contingency funding for a project. Furthermore, some of EM's guidance includes vague language and various exceptions to rules, which are likely to contribute to a project manager's difficulty in determining how to implement EM policy. For example, according to the April 2007 protocol for cleanup projects, once a contract is awarded and a detailed near-term baseline is developed, a follow-up independent review will be required if the baseline (1) exceeds the previously validated near-term baseline costs by 15 percent or more, (2) increases the schedule by a year, or (3) modifies scope significantly. The first two conditions for requiring a follow-up review are tied to fairly precise numbers—15 percent and 1 year—although there could be some question as to whether these numbers are to be applied to the original or reset baseline calculations, especially for projects that have been extended multiple times. However, the protocol provides no parameters for determining when the third condition, a "significant" scope modification, has occurred.

In addition, agency officials were not able to provide us with formal documentation of a significant shift in policy. As explained earlier, OECM recently shifted from validation to certification of the cleanup projects' near-term baselines. In response to our request for documentation of the switch to certification, OECM provided us with an e-mail from an OECM official to a DOE Inspector General auditor that defined certification and explained the reasons for the change. According to this e-mail, the change was made to acknowledge OECM's belief that EM cleanup projects should not be reviewed under the same standard as construction projects. The OECM official also directed us to DOE's fiscal year 2009 budget request for an explanation of the new approach. While the budget request includes a description of baseline certification, it neither mentions that the certification is a departure from the previous policy, nor does the request serve as an adequate means of communicating a significant policy change.

Furthermore, different guidance documents appear to be in conflict with one another. Specifically, EM's 2006 memo outlining its policy on contingency funding explained that DOE's risks associated with implementing a project are covered through contingency that is part of the "unfunded" portion of the baseline; that is, its funding is not requested or budgeted in advance of when it may be needed. However, a 2008 EM memo primarily concerned with explaining a new process for entering baseline changes into a database contains a description of the elements of a near-term baseline that includes a line for "other funded contingency,"

which has been interpreted by some EM officials as including DOE contingency. If, according to the 2008 memo, some DOE contingency should be funded—requested in advance—that memo directly contradicts the guidance provided in the 2006 memo. However, although the 2008 memo states it is updating the baseline change process, it does not specifically state that it replaces any part of the 2006 memo.

In part because of this confusion, project managers at cleanup sites have been implementing EM's contingency policy differently. According to EM officials, recent independent reviews have alerted senior EM officials to this inconsistent implementation of the policy guidance. The review teams found that the project managers were using a variety of methodologies to calculate the contingency for their projects. As a result, according to one EM official with expertise in contingency, managers were likely underestimating the amount of contingency needed for their projects. To address this problem, EM senior managers directed the creation of a contingency implementation guide to provide a definitive interpretation of existing EM policy on contingency, and this guide is expected to be issued in September 2008.

Furthermore, at least one of DOE's policies—on independent reviews of cost estimates—is not being implemented at all. According to Order 413 and the April 2007 protocol, an independent cost estimate—a top-to-bottom, independent estimate that serves to cross-check a cost estimate developed by project officials—should be developed as part of the OECM review process for major projects when "complexity, risk, cost, or other factors create a significant cost exposure for the Department." We believe that a review of a major cleanup project, given its level of expected spending over the near term, would meet the criteria for requiring an independent cost estimate. According to an OECM official, OECM has not performed an independent cost estimate for any of EM's major cleanup projects, primarily because OECM lacks the resources required to perform this type of rigorous estimate for the projects. Instead, OECM has taken a less rigorous and less expensive approach in its reviews—examining cost estimates generated by the projects but not producing a separate estimate for comparison.

According to DOE officials, it is addressing some of these guidance issues. By the end of September 2008, officials told us, DOE plans to replace its manual directing implementation of Order 413 with a series of 16 guides. The guides are expected to cover a range of project management issues, including risk management and contingency funding, with one guide providing direction on the management of EM cleanup projects. In

addition to the guides, as part of an EM-wide effort to improve project performance, EM has issued 18 recommended priority actions that contain additional EM-specific requirements for cleanup projects. It is unclear whether the guides and priority actions are expected to supplant all other guidance, or whether they will adequately address the challenge project managers face in determining the most up-to-date, comprehensive guidance to be followed.

DOE Recently Changed Expectations for Cleanup Projects' Performance

According to EM senior managers, EM cleanup projects are significantly different from DOE's construction projects in a number of ways. That is, it is harder in many instances to clearly define up-front requirements for cleanup projects, and there are more unknowns, especially since some of these projects are the first of their kind, with undefined scopes of work and significant risks scheduled many years into the future. Because of these differences and because it has said changing budget priorities may affect funding over time, DOE recently changed its performance goal—the amount of work to be accomplished and the cost margin for accomplishing that work—for EM cleanup projects to reflect a much larger margin of error than the performance goal set for construction projects.

Before 2008, a major cleanup project was measured against the same goal as a construction project: achieve at least 100 percent of the scope of work in its baseline with less than a 10 percent cost increase over the life of the project.[37] However, EM's current cleanup project performance goal applies only to the near-term baseline, and the projects now are considered to be successful if they achieve at least 80 percent of the scope of work in their near-term baselines with less than a 25 percent cost increase. The new performance goal permits up to 20 percent of the scope of work to be deferred from the near term to out years, which creates a substantially greater risk that life cycle costs will continue to increase and that completion dates will be delayed. As a result, for example, under this goal the four major projects each expected to cost more than $2 billion in the near term could increase their costs by $500 million each over that period and be considered successful. Furthermore, because a directed change—defined as a change caused by DOE policy, or regulatory or statutory

[37]As previously reported in GAO-07-518, in 2004 DOE began reporting performance information for EM cleanup projects against the same goal as the line-item construction projects. In late 2005, however, DOE switched to reporting performance only for those projects with validated cost and schedule baselines.

actions—already exempts projects from meeting the performance goals, creating a less stringent goal for EM cleanup projects further waters down the impact of having a performance goal in the first place. By lowering expectations for adhering to near-term baselines, DOE inadvertently may be creating an environment in which large increases to project costs become not only more common, but accepted and tolerated.

DOE Is Undertaking Efforts to Implement Project Management Improvements

EM is undertaking a number of efforts to improve its project performance and address long-standing problems. One such effort is EM's "Best-in-Class" Project Management Initiative through which EM leadership has committed to improving project performance. Under the initiative, EM contracted with the Army Corps to assess the current status of project management at EM headquarters and its offices. Using the Army Corps' analysis, EM identified a set of challenges it faced in executing its mission, which resulted in the creation of the 18 priority actions for it to undertake to address the challenges and implement its initiative. Those priority actions include, among others, completing DOE's project management guide, which is expected to bring all project management guidance documents under one umbrella document; establishing standard reporting formats for project updates produced by project managers, including QPRs; implementing new project management software packages, including those for EVM analysis; and better integrating its project and contract management activities. EM has developed a set of implementing steps and a summary of expected benefits for each priority action. According to EM, 10 of the priority actions are being implemented in fiscal year 2008, and 5 of those are scheduled to be completed by the end of that fiscal year. It appears that execution of the priority actions would create new tools and potentially enhance existing ones in EM's effort to improve its cleanup projects' performance. According to EM, full implementation of the priority actions will address many EM project management problems and deficiencies. However, since the actions are still being implemented, it is too soon to determine their effectiveness.

In addition, EM officials acknowledged that the actions they are implementing to improve the management of EM's overall cleanup efforts, including their Best-in-Class initiative and actions being taken in response to the 2007 National Academy of Public Administration report have not been formally documented into a specific, corrective action plan that includes performance metrics and completion milestones. These officials agreed that such a comprehensive plan would demonstrate a more integrated and transparent commitment to improving the management of EM's cleanup projects.

Conclusions

Cleaning up the nuclear weapons complex is a technically challenging and risky business. Even as DOE works to gain control of and better manage its major nuclear waste cleanup projects, cost increases and project delays continue to mount. Specifically, life cycle costs for EM's major cleanup projects have increased by cumulative $25 billion over the past few years and schedules have been extended by a combined total of more than 75 years, primarily because DOE had to adjust the optimistic baselines it created to accommodate the realities it has encountered at its cleanup projects.

Given the cost and complexity of the major nuclear cleanup projects, it is critically important that DOE fully use the tools it has developed—independent reviews, performance information systems, guidance, and performance goals—to better ensure that projects stay within established parameters for scope of work, costs, and schedule. Independent baseline reviews to ensure that the work promised can be completed on time and for the estimated cost appear to be a useful planning tool, but the significant changes that have occurred within years or even months of the baseline reviews and validations indicate that implementation of these reviews has fallen short. Furthermore, EM's site proposals for changes to cost and schedule baselines, quarterly performance reports, earned value data analysis and reports, and reports to Congress do not consistently provide accurate and comprehensive information on the status of projects, which undermines managers' and Congress's ability to effectively oversee projects and make timely decisions, such as targeting resources to particular projects or renegotiating cleanup milestones and other contract conditions. These problems are compounded by the lack of comprehensive and clear guidance for DOE project managers so that they consistently implement DOE management policies across the projects and EM's recently relaxed performance goals establishing the acceptable baseline change parameters for major cleanup projects. Although DOE has identified a number of improvements it intends to make to its project management approach, it is still in the early stages of implementing these improvements, making it too soon to assess the effort's full effect, and it has not yet formally documented all the improvements in a comprehensive corrective action plan.

Recommendations for Executive Action

So that DOE can better manage its major cleanup projects and more fully inform Congress on the status of these projects, we recommend that the Secretary of Energy direct the Assistant Secretary for Environmental Management to take the following five actions:

- Include in its budget request to Congress life cycle baseline cost estimate information for each cleanup project, including prior year costs, estimated near-term costs, and estimated out-year costs.

- Develop an approach to regularly inform Congress of progress and significant changes in order to improve EM's accountability for managing the near-term baseline and tracking life cycle costs. Similar to the Department of Defense's Selected Acquisition Reports, which include annual information on full life cycle program costs, among other things, EM's report, at a minimum should compare estimated near-term and life cycle scope, cost, and schedules with the original and subsequently updated baselines, and provide a summary analysis of root causes for any significant baseline changes.

- Expand the content of EM performance reports to describe the implications of current performance for the project's overall life cycle baseline, including the near-term baseline cost and out-year cost estimate, using, when appropriate, valid earned value data that conform to industry standards and GAO-identified best practices.

- Consolidate, clarify, and update its guidance for managing cleanup projects to reflect (1) current policy regarding independent baseline reviews and (2) the results of DOE's determination of the appropriate means for calculating and budgeting for contingency so that project managers can consistently apply it across nuclear waste cleanup sites.

- Consolidate all planned and ongoing program improvements, including those stemming from the Secretary's contract and project management root cause analysis corrective action plan, the Best-in-Class initiative, and the 2007 National Academy of Public Administration report, into a comprehensive corrective action plan that includes performance metrics and completion milestones.

Because independent baseline reviews have not always provided reasonable assurance of the stability of projects' near-term baselines or the reasonableness of the life cycle baselines, we recommend that the Secretary of Energy direct the Director of the Office of Management to take the following action:

- Assess the Office of Engineering and Construction Management's current approach and process for conducting baseline reviews of EM cleanup projects to identify and implement improvements that will better provide reasonable assurance that project work scope can be completed within the baselines' stated cost and schedule. Consider including in the

assessment process an analysis of past lessons learned and reasons for baseline changes, and an assessment of project affordability when conducting baseline reviews.

Agency Comments and Our Evaluation

We provided a draft of this report to DOE for its review and comment. DOE agreed with our recommendations but provided some suggested changes to them, which we incorporated as appropriate.

In addition, DOE provided some specific comments on our draft report. First, DOE stated that the report should provide a more balanced and accurate portrayal of EM's cleanup projects by including descriptions of ongoing initiatives, a number of which EM launched in recognition of the need for improvement, as well as providing better context of the challenges and constraints the department's cleanup program faces. The draft report included a brief description of EM's ongoing initiatives, including its Best-in-Class effort, and acknowledged many of the key challenges DOE faces while illustrating the factors contributing to changes in scope, cost, and schedule for its cleanup projects. We also acknowledged DOE's ongoing initiatives and progress in a 2007 report on project management.[38] In addition, DOE cited its successes in the cleanup of Rocky Flats and Fernald as evidence of its project management accomplishments. We commend DOE on its past performance in successfully cleaning up these sites, which has resulted in some lessons learned that DOE can apply to other cleanup efforts, as we reported in 2006.[39] Nevertheless, we found in this review that DOE has not always effectively used its management tools to help oversee the scopes of work, costs, and schedules for its present major cleanup projects.

Second, DOE stated that our draft report appears to confuse the term "baseline." It noted that there is only one project baseline—the near-term baseline approved by EM senior management—for which DOE should be held accountable. Our use of the term "baseline" in this report conforms to EM's guidance documents indicating a project's "lifecycle baseline" is composed of its prior year, near-term, and out-year costs. In addition, we disagree with DOE's assertion that it should be held accountable only for a project's near-term baseline. As we state in this report, since projects encountering problems have tended to manage those problems by moving work scope into the out years, the effects of problems occurring today

[38] GAO-07-518.

[39] GAO, *Nuclear Cleanup of Rocky Flats: DOE Can Use Lessons Learned to Improve Oversight of Other Sites' Cleanup Activities*, GAO-06-352 (Washington, D.C.: July 10, 2006).

show up as increases to out-year cost and schedule estimates and not as increases or delays in a near-term baseline. Therefore, if DOE's performance is measured solely on the basis of the near-term baseline, potentially significant cost and schedule increases would not be accounted for or transparent.

Third, DOE stated that one of our recommendations—to consolidate, clarify, and update its guidance for managing cleanup projects to reflect the results of DOE's determination of the appropriate means for calculating and budgeting for project contingency—could be more specific, and it outlined three contingency options. These options include (1) increasing the amount of contingency funding for cleanup projects to an 80 percent confidence level, the level budgeted for construction projects; (2) creating a general contingency fund available for project managers at DOE headquarters to dispense as needed to manage project risks; and (3) continuing with the current approach of not including contingency funding for cleanup projects in its budget requests—funding cleanup projects at the 50 percent confidence level—and changing its recently established performance goal. We recognize that managing project contingency is an important issue, and in fact note in our report that DOE's current approach is a likely contributing factor to cost increases and schedule delays for EM's major cleanup projects. While we did not specifically assess these three options in our report, DOE should continue to study the lessons learned from managing and budgeting contingency and select the option that would provide contingency funds in an expedient manner to better mitigate the impacts of cleanup project changes while minimizing the amount of unused contingency funding left over at the end of the fiscal year.

Finally, as part of the explanation of its third option for funding project contingency, DOE stated that GAO has agreed to its recently established performance goal—to accomplish at least 80 percent of the scope of work in the near-term baselines with less than a 25 percent cost increase. GAO has not agreed to this goal. As we state in this report, we are concerned with DOE's new goal given that it is lower than the previous goal for cleanup projects and that DOE may inadvertently be creating an environment in which large increases to project costs become not only more common, but accepted and tolerated.

DOE also provided detailed technical comments, which we have incorporated into our report as appropriate. DOE's comments are reproduced in appendix IV.

We are sending copies of the report to interested congressional committees, the Secretary of Energy, and the Director of the Office of Management and Budget. We will make copies available to others on

request. In addition, the report will also be available at no charge on the GAO web site at http://www.gao.gov.

If you or your staffs have any questions about this report, please contact me at (202) 512-3841 or aloisee@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. Other staff contributing to the report are listed in appendix V.

Gene Aloise
Director, Natural Resources
and Environment

Appendix I: Scope and Methodology

To determine the extent to which the cost, schedule, and scope baseline estimates for the Department of Energy (DOE) Office of Environmental Management's (EM) cleanup projects have changed and the key reasons for these changes, we identified 10 major cleanup projects at 5 DOE sites. We first identified 9 major cleanup projects with current near-term cost estimates (usually a 5-year period) above $1 billion, the DOE threshold for major cleanup projects. In addition, to include those projects that could potentially become major projects because of cost growth, we reduced the threshold to $900 million and identified another project, the Richland nuclear material stabilization and disposition project, which is estimated to cost between $900 million and $1 billion over the near term. We focused on these 10 major cleanup projects because of their significant cost—combined estimated near-term costs of about $19 billion and combined life cycle costs estimated at more than $100 billion—and because they account for almost half of EM's $5.5 billion fiscal year 2009 budget request. (See app. II for information on these projects.)

To identify the factors that may hinder DOE's ability to effectively manage these cleanup projects, we spoke with DOE project directors and contractor officials and reviewed project management documents for the 10 major cleanup projects we had identified. We conducted site visits to Idaho National Laboratory, Los Alamos National Laboratory, Oak Ridge Reservation, Savannah River, and Hanford, and analyzed project documentation—contracts, policy directives and memoranda, project management plans, DOE's Office of Inspector General reports, independent reviews, project execution plans, risk management plans, quarterly project reviews, monthly project status reports, earned value management (EVM) surveillance plans, and project control documents prepared to guide and control formal changes to the baselines. For our analysis of projects' scope, cost, and schedule data, we examined the initial baselines reported as of the most recent contract award or major contract modification (which occurred between 2004 and 2007) and compared these baselines with the updated baselines at the time of our review. Initial cost baselines are the estimated life cycle costs at the beginning of the new contract period for operation of the DOE site or associated projects or the major contract modification or extension, which typically coincided with the beginning of the projects' current or previous near-term baseline. We also calculated the percentages of cost increases on the basis of constant 2008 dollars to make them comparable across projects and to show real increases in cost while excluding increases due to inflation. In addition, because EM now is reporting its life cycle cost and schedule estimates as ranges, we included these ranges in the report. However, because the upper ends of these ranges include unfunded

contingency and EM does not include funding in its budget requests for this contingency, we report cost increases and schedule delays based on the lower ends of the ranges.

We also analyzed contractor performance data to determine whether DOE major cleanup projects are consistently developing and analyzing accurate earned value data according to industry standards and best practices. We gathered and analyzed data produced by the EVM system used for one project at each of the following sites: Idaho National Laboratory, Los Alamos National Laboratory, and Hanford.[1] Often, EVM systems differ depending on how the contractor chooses to implement the EVM approach. Because of these differences, we gathered and analyzed information on each EVM system on a case-by-case basis, according to the structure, reporting format, content, and level of detail, among other things, unique to each EVM system. We also considered the best practices developed by GAO for estimating and managing project costs to analyze the contractor EVM data.[2]

In addition, we spoke with DOE officials from EM and the Office of Engineering and Construction Management in Washington, D.C., and with representatives from LMI Government Consulting, which conducts external independent reviews of the projects for DOE, to obtain their perspective on how these projects are managed.

Because we and others previously have expressed concern about the data reliability of a key DOE project management tracking database—the Project Assessment and Reporting System—we did not develop conclusions or findings based on information generated through that system.[3] Instead, we collected information directly from project site offices and the contractors.

[1]We did not analyze the EVM data for the Oak Ridge or Savannah River projects.

[2]GAO, *Cost Assessment Guide: Best Practices for Estimating and Managing Program Costs*, GAO-07-1134SP (Washington D.C.: July 2007).

[3]GAO, *Department of Energy: Further Actions Are Needed to Strengthen Contract Management of Major Projects*, GAO-05-123 (Washington, D.C: Mar. 18, 2005); and Civil Engineering Research Foundation, *Independent Research Assessment of Project Management Factors Affecting Department of Energy Project Success* (Washington, D.C.: July 12, 2004).

We provided an interim briefing to the Subcommittee on Energy and Water Development, House Committee on Appropriations, on the status of our work on April 3, 2008.

We conducted this performance audit from March 2007 to September 2008 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Appendix II: Information on the 10 Department of Energy Major Cleanup Projects Reviewed

Project	Project purpose and objective
Solid Waste Stabilization and Disposition, Idaho National Laboratory, Idaho (PBS 13)	This project will characterize, treat, and ship approximately 64,000 cubic meters of transuranic waste that will ultimately be stored in the Waste Isolation Pilot Plant in New Mexico. Transuranic waste is radioactive waste containing more than 100 nanocuries of alpha-emitting transuranic isotopes per gram of waste with half-lives greater than 20 years, except for high-level radioactive waste. The transuranic waste that must be handled remotely through protective shielding, because it emits penetrating radiation, will be treated at the Radioactive Waste Management Complex. The project also will treat and dispose of a mixed low-level waste backlog and handle on-site low-level waste for disposal at the complex.
Nuclear Facility Decontamination and Decommissioning, Oak Ridge Reservation Tennessee (PBS 40)	The project will decontaminate and decommission approximately 500 facilities and remediate 160 sites in the East Tennessee Technology Park. This project includes the park's two major buildings—the K-25 and K-27 gaseous process buildings—and requires the contractor to remove processing equipment and excess materials stored in the buildings, demolish building structures, and dispose of all associated wastes.
Nuclear Material Stabilization and Disposition, Savannah River Site, South Carolina (PBS 11)	The project will stabilize and dispose of enriched uranium materials and current and projected inventories of aluminum-clad spent nuclear fuel in H-Area facilities. It also will stabilize and dispose of highly enriched uranium solutions, miscellaneous fuels, plutonium residues, enriched uranium residues, and other materials DOE identifies that remain from the production of nuclear weapons. The project also will deactivate F-Area and H-Area facilities; and dispose of special nuclear materials in the K-Area Complex.
Radioactive Liquid Tank Waste Stabilization and Disposition, Savannah River Site, South Carolina (PBS 14C)	The project will remove, treat, and dispose of 49 underground storage tanks holding a total of 37 million gallons of highly contaminated legacy waste This effort includes pretreating radioactive waste such as sludge and salt waste, vitrifying sludge and high-level waste at the Savannah River Site's Defense Waste Processing Facility, and treating and disposing of low-level saltstone waste.
Soil and Water Remediation, Los Alamos National Laboratory, New Mexico (PBS 30)	The project will identify, investigate, and remediate, when necessary, areas with known or suspected chemical and radiological contamination attributable to past Laboratory operations. It will investigate and clean up (as needed) approximately 860 solid waste management units and areas of concern remaining from the original 2,129 sites spread over approximately 39 square miles. The protection of surface water and groundwater resources that may be impacted by these management units and past Laboratory operations also are within the scope of this project.
Nuclear Material Stabilization and Disposition, Hanford, Washington (PBS 11)	The project will stabilize, package, and ship (to the Savannah River Site) nuclear materials and fuels used for the production of plutonium nitrates, oxides, and metal from 1950 through 1989 and now stored primarily in vaults in several facilities. The project will then clean and demolish the facilities.
Solid Waste Stabilization and Disposition, Hanford, Washington (PBS 13C)	The project will treat and store spent nuclear fuel, transuranic waste, mixed low-level waste, and low-level waste generated at the Hanford site and other DOE and Department of Defense facilities. It eventually will transfer and ship spent nuclear fuel elements and 1,936 cesium and strontium capsules to the proposed geologic repository in Nevada. The project also will operate, among other things, the (1) Waste Receiving and Processing Facility to process transuranic waste and low-level waste and (2) Central Waste Complex to store low-level and mixed-low-level waste and transuranic waste pending final disposition.

Project	Project purpose and objective
Soil and Water Remediation, Hanford, Washington (PBS 30)	The project will remediate contaminated groundwater. This effort involves characterizing the movement of radionuclides and chemicals (carbon tetrachloride, chromium, technetium-99, strontium, and uranium plumes); assessing the soil and groundwater characterization results; groundwater and risk assessment modeling; and operation of groundwater remediation systems among other related actions.
Nuclear Facility Decontamination and Decommissioning at River Corridor Closure Project, Hanford, Washington (PBS 41)	Also known as the River Corridor Closure Project, this project will remediate 761 contaminated waste sites at the Hanford site near Richland, Washington, and decontaminate, decommission and demolish 379 surplus facilities that are adjacent to the Columbia River. This project also will dispose of material in the Environmental Restoration Disposal Facility.
Radioactive Liquid Tank Waste Stabilization and Disposition, Office of River Protection, Hanford, Washington (PBS 14)	The project will retrieve, stabilize, treat, and dispose of 53 million gallons of radioactive mixed waste stored in 177 underground tanks at the Hanford site. The project also involves testing and implementing supplemental waste treatment methods; operating the Waste Treatment Plant; providing interim storage of immobilized waste planned for disposal in an offsite repository; receiving and disposing of immobilized low-activity waste on-site in near-surface disposal facilities; and closing tanks and tank farm facilities.

Source: DOE and EM information.

Appendix III: Current Life Cycle Baselines for 10 DOE Cleanup Projects

Dollars in millions (current year dollars)

Project	Prior years' costs	Near term[a] Cost	Near term[a] Years	Out years[b] Cost	Out years[b] Completion date	Total life cycle cost range
Solid waste stabilization and disposition, Idaho National Laboratory, Idaho	$1,398	$1,304	2006 – 2012	$530 – $900	2016 – 2020	**$3,231 – $3,954**
Nuclear facility decontamination and decommissioning, Oak Ridge Reservation, Tennessee	$1,546	$1,518	2008 – 2017	NA	NA	**$3,064 – $3,244**
Nuclear material stabilization and disposition, Savannah River Site, South Carolina	$3,631	$2,468	2008 – 2014	$3,728 – $4,358	2024 – 2025	**$9,827 – $10,457**
Radioactive liquid tank waste stabilization and disposition, Savannah River Site, South Carolina	$4,746	$4,394	2008 – 2014	$11,856 – $20,347	2032 – 2034	**$20,996 – $29,488**
Soil and water remediation, Los Alamos National Laboratory, New Mexico	$579	$1,051	2007 – 2015	NA	NA	**$1,630 – $2,489**
Nuclear material stabilization and disposition, Hanford site, Washington	$1281	$1,143	2008 – 2013	$1,030 – $1,060	2018 – 2019	**$3,453 – $3,490**
Solid waste stabilization and disposition, Hanford site, Washington	$1,163	$918	2008 – 2013	$11,200 – $12,500	2050 – 2058	**$13,281 – $14,594**
Soil and water remediation, Hanford site, Washington	$532	$1.128	2008 – 2013	$6,400 – $6,600	2050 – 2059	**$8,059 – $8,276**
Nuclear facility decontamination and decommissioning at River Corridor, Hanford site, Washington	$1,000	$3,751	2005 – 2019	NA	NA	**$4,751 – $4,910**
Radioactive liquid tank waste stabilization and disposition, Hanford site, Washington	$3,474	$2,330	2007 – 2012	$38,414 – 5$6,227	2042 – 2050	**$44,218 – $62,155**

Source: Office of Environmental Management.

[a]Near-term costs represent DOE's estimated costs based on a 50 percent level of confidence, defined as the amount of funding needed to provide a 50 percent likelihood that the project will be completed successfully.

[b]Out-year values represent DOE's estimated cost and schedule ranges—the cost range covers the full out-year period, while the schedule range represents the time during which the project is estimated to be completed. Costs and schedules at the lower end of the ranges were estimated at the 50 percent level of confidence, while costs and schedules at the upper end of the ranges represent the 80 percent level of confidence.

Appendix IV: Comments from the Department of Energy

Department of Energy
Washington, DC 20585

September 19, 2008

Mr. Gene Aloise
Director of Natural Resources and Environmental
U.S. Government Accountability Office
441 G Street NW
Washington, D.C. 20548

Dear Mr. Aloise:

Thank you for the opportunity to review the draft report on accountability and management of the Department's major cleanup projects managed by the Department of Energy's Office of Environmental Management (EM). We are in agreement with the recommendations you have provided, with some suggested changes, and look forward to reporting in the future on the progress being made. Detailed comments to the draft report are enclosed. Major comments are summarized below.

We believe the report should provide a more balanced and accurate portrayal of EM's cleanup projects by including descriptions of ongoing initiatives and actions, a number of which were launched by EM in recognition of the need for improvement. Additionally, the report should provide better context of the incredible challenges and constraints the Department's cleanup program faces and the difficulties associated with accurate predictions of project cost and schedule for the EM cleanup projects.

For instance, the Government Accountability Office's (GAO) conclusion in 2001 (GAO-01-284, *Nuclear Cleanup: Progress Made at Rocky Flats, but Closure by 2006 Is Unlikely, and Costs May Increase)* states that "Kaiser-Hill and DOE are unlikely to meet the December 2006 target closure date" for Rocky Flats and yet this closure date was indeed met by DOE and the Rocky Flats cleanup contractor Kaiser-Hill. As recommended by the GAO in 2006 (GAO-06-352, *Nuclear Cleanup of Rocky Flats: DOE Can Use Lessons Learned to Improve Oversight of Other Sites' Cleanup Activities),* EM used the lessons learned from Rocky Flats for other cleanup efforts across the complex to accomplish extremely successful cleanups. We won the Project Management Institute award for our prowess in project management in 2006 and 2007 for the Rocky Flats and Fernald cleanup projects, respectively.

There appears to be some confusion over the term "baseline". There is only one project baseline, the near-term baseline that has Critical Decision-2 approval by the Acquisition Executive, for which DOE should be held accountable. The

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Decision-1 type range) which is expected to change, often by significant amounts. For this very reason, DOE no longer expresses lifecycle information on cleanup projects as a point estimate.

Finally, the issue of how we fund and manage project contingency is critical to our long-term success and our ability to mitigate impacts of these changes. We recognize full well that we cannot continue to extend schedules and increase costs every time risks that have been identified and anticipated in advance occur. Your fourth recommendation, with regard to contingency, could be more specific. There are three primary or bounding contingency options as we see it, discussed further in the attachment:

1. **Fund operating cleanup project contingency at 80% confidence level instead of the current 50%.**
   If provided over and above current target levels, approximately $500 million (M) to $700M additional funding annually would be required. However, if risks did not materialize during the budget year, there would be higher uncosted year-end carryover. However, to plan for this level of contingency without additional funding would require deferral of lower priority project scope. To compensate, EM would need to renegotiate compliance milestones or possibly subject the federal government to fines, penalties, and lawsuits; renegotiate and possibly terminate contracts, thus affecting employment; and reprioritize its projects.
2. **Request appropriation of a smaller general contingency fund.**
   The fund (perhaps $100M to $200M annually) would be held, managed, and distributed by the Assistant Secretary for Environmental Management. This option would allow more flexibility and expediency in applying funds where they are needed as risks are realized, and would allow for multi-year business case decision-making. However, controls would need to be put in place on EM's allocation authority during execution so as not to usurp Congressional authority in appropriations.
3. **Continue the current approach of funding 50% confidence levels and changing the corporate metric for the EM cleanup projects agreed to by DOE, the Office of Management and Budget (OMB), and GAO.**
   This approach budgets for contingency at a 50% confidence level for cleanup projects. When risks not covered at this level materialize, work scope is shifted to the outyears when funds can be requested in light of overall program priorities. A 50% confidence level across the EM portfolio connotes that based on statistical analysis half the projects would be expected to be completed within the cost and schedule and half would not. Thus, this current approach appears to be inconsistent with achieving success in the corporate metric that DOE has agreed to with GAO and OMB for cleanup projects (established through DOE's Root Cause Analysis Corrective Action Plan, July 18, 2008). The metric requires that 90% of the projects in EM's portfolio at the end of the approved near-term

baseline period have 80% of the scope completed within 25% of the original cost.

Any GAO recommendations regarding new strategies are welcomed, given the regulatory-driven nature and complexity of this work, the sensitivity of life-cycle costs to relatively small slippages in scope (due to large "hotel" costs), and the need to deliver on commitments made to our regulators, the Congress, and other stakeholders.

Again, thank you for your assistance as we seek to improve our management of cleanup projects. We welcome direct dialogue with you on these issues prior to finalizing your report. We would also appreciate you including the attached comments in the final report. If you have any questions with regard to these comments, please contact me on (202)586-7709, Jack Surash on (202) 586-6382, or Paul Bosco on (202) 586-3524

Sincerely,

James A. Rispoli
Assistant Secretary for
Environmental Management

Enclosure

cc: I. Triay, EM-2
J. Owendoff, EM-3
J. E. Surash, EM-50
M. Sykes, EM-30
I. Kolb, MA-1
P. Bosco, MA-50

Appendix V: GAO Contact and Staff Acknowledgments

GAO Contact

Gene Aloise, (202) 512-3841 or aloisee@gao.gov

Staff Acknowledgments

In addition to the individual named above, Rudy Chatlos, Jennifer Echard, James Espinoza, Daniel Feehan (Assistant Director), Mike Gallo, Diane Lund, Mehrzad Nadji, Omari Norman, Brian Octeau, Christopher Pacheco, Leslie Pollock, Karen Richey, and Carol Herrnstadt Shulman made key contributions to this report.

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Home> NRC Library> Document Collections > Fact Sheets > Backgrounder on Decommissioning Nuclear Power Plants

Backgrounder on Decommissioning Nuclear Power Plants

Printable Version
Decommissioning (video)

On this page:

- Discussion
- Regulations
- Decommissioning Funds
- Public Involvement
- Improving the Decommissioning Program
- Phases of Decommissioning
- Power Reactors in the Decommissioning Process

When a power company decides to close a nuclear power plant permanently, the facility must be decommissioned by safely removing it from service and reducing residual radioactivity to a level that permits release of the property and termination of the operating license. The Nuclear Regulatory Commission has strict rules governing nuclear power plant decommissioning, involving cleanup of radioactively contaminated plant systems and structures, and removal of the radioactive fuel. These requirements protect workers and the public during the entire decommissioning process and the public after the license is terminated.

Discussion

Licensees may choose from three decommissioning strategies: DECON, SAFSTOR or ENTOMB.

Under DECON (immediate dismantling), soon after the nuclear facility closes, equipment, structures, and portions of the facility containing radioactive contaminants are removed or decontaminated to a level that permits release of the property and termination of the NRC license.

Demolition of a Reactor Containment Building

Under SAFSTOR, often considered "deferred dismantling," a nuclear facility is maintained and monitored in a condition that allows the radioactivity to decay; afterwards, the plant is dismantled and the property decontaminated.

Under ENTOMB, radioactive contaminants are permanently encased on site in structurally sound material such as concrete. The facility is maintained and monitored until the radioactivity decays to a level permitting restricted release of the property. To date, no NRC-licensed facilities have requested this option.

The licensee may also choose to adopt a combination of the first two choices in which some portions of the facility are dismantled or decontaminated while other parts of the facility are left in SAFSTOR. The decision may be based on factors besides radioactive decay, such as availability of waste disposal sites.

Decommissioning must be completed within 60 years of the plant ceasing operations. A time beyond that would be considered only when necessary to protect public health and safety in accordance with NRC regulations.

TOP

Regulations

The requirements for decommissioning a nuclear power plant are set out in several NRC regulations.[1] In August 1996, a revised rule went into effect that redefined the decommissioning process and required owners to provide the NRC with early notification of planned decommissioning activities. The rule allows no major decommissioning activities to be undertaken until after certain information has been provided to the NRC and the public.

Decommissioning Funds

Before a nuclear power plant begins operations, the licensee must establish or obtain a financial mechanism – such as a trust fund or a guarantee from its parent company – to ensure there will be sufficient money to pay for the ultimate decommissioning of the facility.

Each nuclear power plant licensee must report to the NRC every two years the status of its decommissioning funding for each reactor or share of a reactor that it owns. The report must estimate the minimum amount needed for decommissioning by using the formulas found in 10 CFR 50.75(c). Licensees may alternatively determine a site-specific funding estimate, provided that amount is greater than the generic decommissioning estimate. Although there are many factors that affect reactor decommissioning costs, generally they range from $300 million to $400 million. Approximately 70 percent of licensees are authorized to accumulate decommissioning funds over the operating life of their plants. These owners – generally traditional, rate-regulated electric utilities or indirectly regulated generation companies – are not required today to have all of the funds needed for decommissioning. The remaining licensees must provide financial assurance through other methods such as prepaid decommissioning funds and/or a surety method or guarantee. The staff performs an independent analysis of each of these reports to determine whether licensees are providing reasonable "decommissioning funding assurance" for radiological decommissioning of the reactor at the permanent termination of operation.

TOP

Public Involvement

The public has several opportunities to participate in the decommissioning process. A public meeting is held in the vicinity of the facility after submittal of a post-shutdown decommissioning activities report to the NRC. Another public meeting is held when NRC receives the license termination plan. An opportunity for a public hearing is provided prior to issuance of a license amendment approving the plan or any other license amendment request. In addition, when NRC holds a meeting with the licensee, members of the public may observe the meeting (except when the discussion involves proprietary, sensitive, safeguards, or classified information).

TOP

Improving the Decommissioning Program

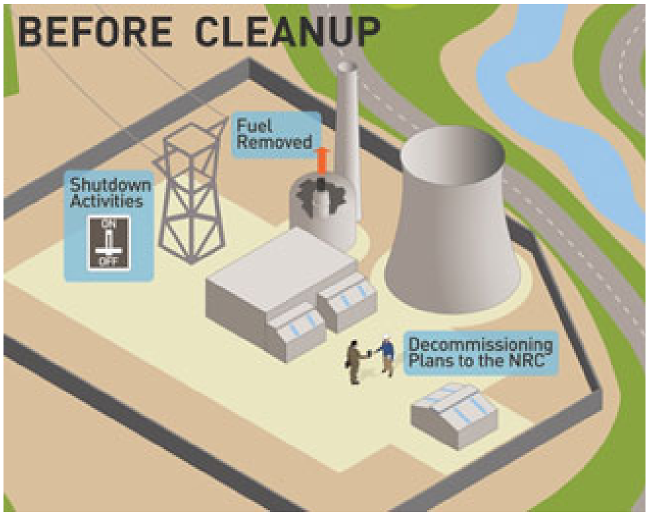
Several nuclear power plants completed decommissioning in the 1990s without a viable option for disposing of their spent nuclear fuel, because the federal government did not construct a geologic repository as planned. Accordingly, the NRC implemented regulations allowing licensees to sell off part of their land once it meets NRC release criteria, while maintaining a small parcel under license for storing the spent fuel. These stand-alone facilities, called "independent spent fuel storage installations," remain under license and NRC regulation. Licensees are responsible for security and for maintaining insurance and funding for eventual decommissioning.

The NRC is currently developing new regulations that will implement lessons learned from transitioning several plants from operation to decommissioning since 2011. These regulations, expected to be final by 2020, will enhance the efficiency and transparency of the transition and the early stages of decommissioning.

TOP

Phases of Decommissioning

The requirements for power reactor decommissioning activities may be divided into three phases: (1) transition; (2) major decommissioning and storage; and (3) license termination activities.



1) Transition from Operation to Decommissioning

When a nuclear power plant licensee shuts down the plant permanently, it must submit a written certification of permanent cessation of operations to the NRC within 30 days. When radioactive nuclear fuel is permanently removed from the reactor vessel, the owner must submit another written certification to the NRC, surrendering its authority to operate the reactor or load fuel into the reactor vessel. This eliminates the obligation to adhere to certain requirements needed only during reactor operation. Other requirements are currently eased through exemptions and license amendments; several of these transitional changes will be included in the new regulations under development.

Within two years after submitting the certification of permanent closure, the licensee must submit a post-shutdown decommissioning activities report to the NRC. This report provides a description of the planned decommissioning activities, a schedule for accomplishing them, and an estimate of the expected costs. The report must discuss the reasons for concluding that environmental impacts associated with the site-specific decommissioning activities have already been addressed in previous environmental analyses. Otherwise, the licensee must request a license amendment for approval of the activities and submit to the NRC details on the additional impacts of decommissioning on the environment.

After receiving the report, the NRC publishes a notice of receipt in the *Federal Register*, makes the report available for public review and comment, and holds a public meeting in the vicinity of the plant to discuss the licensee's intentions.

2) Major Decommissioning Activities

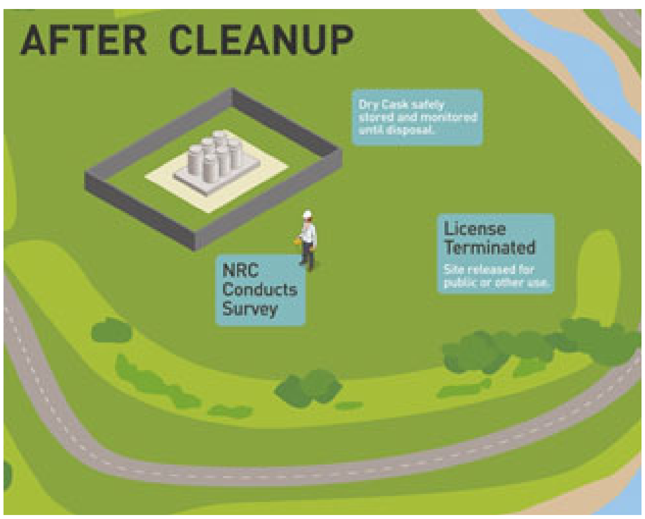
Ninety days after the NRC receives the planning report, the owner can begin major decommissioning activities without specific NRC approval. These include permanent removal of such major components as the reactor vessel, steam generators, large piping systems, pumps, and valves.

However, decommissioning activities conducted without specific prior NRC approval must not prevent release of the site for possible unrestricted use, result in there being no reasonable assurance that adequate funds will be available for decommissioning, or cause any significant environmental impact not previously reviewed. If any decommissioning activity does not meet these terms, the licensee is required to submit a license amendment request, which would provide an opportunity for a public hearing.

Initially, the owner can use up to 3 percent of its set-aside funds for decommissioning planning. The remainder becomes available 90 days after submittal of the planning report unless the NRC staff has raised objections.

3) License Termination Activities

The owner is required to submit a license termination plan within two years of the expected license termination. The plan addresses each of the following: site characterization, remaining site dismantlement activities, plans for site remediation, detailed plans for final radiation surveys for release of the site, updated estimates of remaining decommissioning costs, and a supplement to the environmental report describing any new information or significant environmental changes associated with the final cleanup. Most plans envision releasing the site to the public for unrestricted use, meaning any residual radiation would be below NRC's limits of 25 millirem annual exposure and there would be no further regulatory controls by the NRC. Any plan proposing release of a site for restricted use must describe the site's end use, public consultation, institutional controls, and financial assurance needed to comply with the requirements for license termination for restricted release.



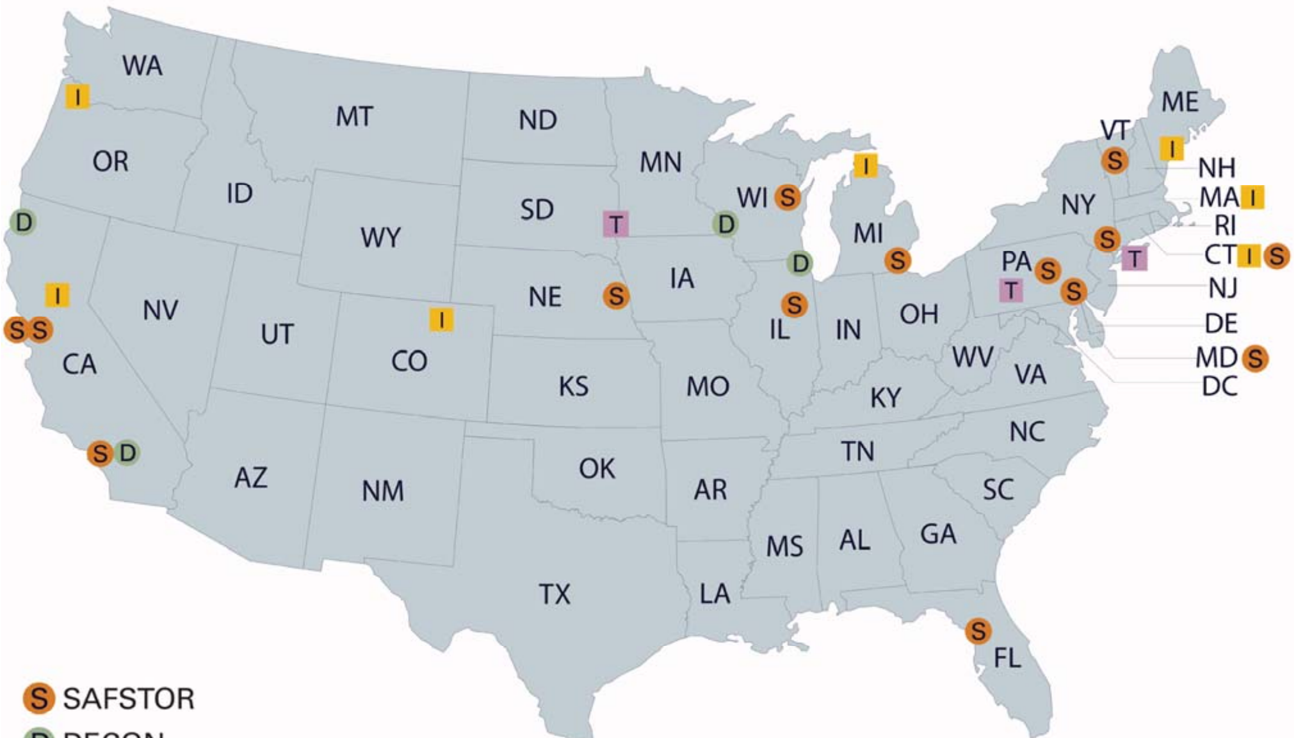
The license termination report requires NRC approval of a license amendment. Before approval can be given, an opportunity for hearing is published and a public meeting is held near the plant site.

The NRC uses a standard review plan (NUREG-1700, "Standard Review Plan for Evaluating Nuclear Power Reactor License Termination Plans") to ensure high quality and uniformity of the license termination plan reviews.

If the remaining dismantlement has been performed in accordance with the approved LTP and the NRC's final survey demonstrates that the facility and site are suitable for release, the NRC issues a letter terminating the operating license.

Current updates of all power reactor sites undergoing decommissioning are available on the NRC Website.

Power Reactors Decommissioning Status



S SAFSTOR

D DECON

Decommissioning Completed

I ISFSI (Independent Spent Fuel Storage Installation) only

T License Terminated (no fuel on site)

CALIFORNIA
- S GE EVESR
- S GE VBWR
- D Humboldt Bay 3
- I Rancho Seco
- S San Onofre 1
- D San Onofre 2 and 3

COLORADO
- I Fort St. Vrain (DOE License)

CONNECTICUT
- S Millstone 1
- I Haddam Neck

FLORIDA
- S Crystal River 3

ILLINOIS
- S Dresden 1
- D Zion 1 and 2

MARYLAND
- S N.S. Savannah

MASSACHUSETTS
- I Yankee Rowe

MAINE
- I Maine Yankee

MICHIGAN
- S Fermi 1
- I Big Rock Point

NEBRASKA
- S Fort Calhoun

NEW YORK
- S Indian Point 1
- T Shoreham

OREGON
- I Trojan

PENNSYLVANIA
- T Saxton
- S Peach Bottom 1
- S Three Mile Island 2

SOUTH DAKOTA
- T Pathfinder

VERMONT
- S Vermont Yankee

WISCONSIN
- D LaCrosse
- S Kewaunee

As of July 2018

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[1] Title 10 of the Code of Federal Regulations, Part 20 Subpart E, and Parts 50.75, 50.82, 51.53, and 51.95

TOP

Page Last Reviewed/Updated Wednesday, August 15, 2018

POLICY ISSUE
(Information)

October 2, 2013 SECY-13-0105

FOR: The Commissioners

FROM: Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

SUBJECT: SUMMARY FINDINGS RESULTING FROM THE STAFF REVIEW OF THE 2013 DECOMMISSIONING FUNDING STATUS REPORTS FOR OPERATING POWER REACTOR LICENSEES

PURPOSE:

This paper informs the Commission of the U.S. Nuclear Regulatory Commission (NRC) staff's findings from the review of the 2013 decommissioning funding status (DFS) reports for operating power reactor licensees. The DFS reports are required under Title 10 of the *Code of Federal Regulations* (10 CFR) 50.75(f)(1). The 2013 DFS reports were due to the NRC by March 31, 2013, reflecting information as of December 31, 2012. This paper does not address any new commitments or resource implications.

BACKGROUND:

In 1988, the NRC established requirements to assure that decommissioning of all licensed facilities will be accomplished in a safe and timely manner and that adequate licensee funds will be available for this purpose. "Decommission" means to remove a facility or site safely from service and reduce residual radioactivity to a level that permits (1) release of the property for unrestricted use and termination of the license; or (2) release of the property under restricted conditions and termination of the license. For reactor licensees, the costs of spent fuel management, site restoration, and other costs not related to termination of the license are not included in the financial assurance for decommissioning.

CONTACT: Shawn W. Harwell, NRR/DIRS
301-415-1309

The requirements for reactor licensees are stated in 10 CFR § § 50.33(k), 50.75, and 50.82. Reactor licensees must certify that they provide not less than a minimum prescribed amount of financial assurance for decommissioning. The amount to be provided must be adjusted annually to account for cost escalation.

In 1998, the NRC amended the financial assurance rules to respond to the anticipated rate deregulation of the power generating industry. The amendments provided additional methods and flexibility for reactor licensees to provide financial assurance. The NRC required licensees to periodically submit a DFS report to obtain the information necessary to monitor the status of decommissioning funds. The Office of Nuclear Reactor Regulation's Office Instruction LIC-205, Revision 4, "Procedures for NRC's Independent Analysis of Decommissioning Funding Assurance for Operating Power Reactors," dated December 2010, (Agencywide Documents Access and Management System (ADAMS) Accession No. ML103410283) describes the analysis performed by the NRC staff to determine if a licensee has provided adequate decommissioning funding assurance.

DISCUSSION:

The NRC staff has reviewed the information in the 2013 DFS reports for all 104 operating nuclear power reactors[1], reflecting power reactor ownership by single or multiple licensees. A table summarizing the review performed by the NRC staff is enclosed and is also available at ADAMS Accession No. ML13266A084.

Results of NRC Staff's Review

The NRC staff's review resulted in the following findings:

- The amount accumulated, as of December 31, 2012, for all operating power reactor licensees totaled $45.7 billion. The total amount accumulated represents a 13.1 percent increase from the total amount accumulated reported in the 2010 DFS reports ($40.4 billion).

- As of December 31, 2012, 100 of the 104 operating nuclear power reactor licensees were providing decommissioning funding assurance, as stipulated in 10 CFR 50.75, "Reporting and Recordkeeping for Decommissioning Planning." The four power reactor licensees that were not providing the full amount of decommissioning funding assurance, as of December 31, 2012, were: Beaver Valley Power Station, Unit 1 (BVPS 1); Palisades Nuclear Plant (Palisades); Perry Nuclear Power Plant (Perry); and Point Beach Nuclear Plant, Unit 2 (Point Beach 2).

- BVPS 1, Palisades, Perry, and Point Beach 2 provided information to resolve their shortfalls in conjunction with their 2012 DFS reports. BVPS 1 and Perry committed to increase the amount of their supplemental parent company guarantees (PCGs); the

[1] As of 12/31/2012, all 104 referenced nuclear power reactors were considered to be in an operating status and reported as such in the 2013 DFS report submittals.

- PCGs were submitted within 90 days after the receipt of the DFS reports. Palisades and Point Beach 2 submitted information showing that their decommissioning trust fund balances increased sufficiently to meet the requirements as of the date of their DFS report submittals.

Resolution of issue not closed out in SECY-11-0149

- Limerick Generating Station, Unit 1 (Limerick 1), had an unresolved shortfall that was identified in SECY-11-0149, "2011 Summary of Decommissioning Funding Status Reports For Nuclear Power Reactors", dated October 26, 2011, (ADAMS Accession No. ML112620046).

- The NRC staff has engaged with the licensee of Limerick 1 and the outstanding shortfall has been resolved. The unresolved shortfall was resolved with rate relief, supplemented with a PCG.

Additional information regarding the 2013 DFS Report Review

The NRC staff noted that many licensees had improved the quality of the information provided in their 2013 DFS report submittals. In particular, the NRC staff required fewer requests for additional information in evaluating the 2013 DFS reports.

CONCLUSION:

Based on the information provided by the licensees in the 2013 decommissioning funding status reports, licensees either did not have shortfalls as of December 31, 2012, or resolved the shortfalls as of the date of this summary.

COORDINATION:

The Office of the General Counsel has reviewed this paper and has no legal objection.

/RA/

Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Enclosure:
2013 DFS Reports – Summary Table

2013 Decommissioning Funding Status Reports - Summary Table

Cat	Plant Name		MWth	Termination Date as of 3/31/2013	NRC Minimum Formula	Site Specific Cost Estimate	Certifying to Site Specific Cost Estimate (Note 1)	Projected Decommissioning Funding Amount including pro rata credit	Difference in NRC Minimum Formula and Projected Trust Fund Amount	How Potential Shortfall was resolved
1	Arkansas Nuclear One, Unit 1	PWR	2568	05/21/2034	$480,031,489	not provided	N/A	$552,033,502	$72,002,013	
1	Arkansas Nuclear One, Unit 2	PWR	3026	07/17/2038	$499,854,754	not provided	N/A	$658,473,004	$158,618,250	
2H	Arnold (Duane) Energy Center	BWR	1912	02/21/2034	$610,877,551	$632,023,000	Yes	$517,858,031	SAFSTOR	
2	Beaver Valley Power Station, Unit 1	PWR	2900	01/29/2036	$508,396,592	not provided	N/A	$493,815,305	($14,581,286)	Parent Company Guarantee
2H	Beaver Valley Power Station, Unit 2	PWR	2900	05/27/2047	$508,396,592	not provided	N/A	$679,913,707	$171,517,116	
2	Braidwood Station, Unit 1	PWR	3586	10/17/2026	$521,778,396	$640,480,000	Yes	$362,247,056	SAFSTOR	
2	Braidwood Station, Unit 2	PWR	3586	12/18/2027	$521,778,396	$699,929,000	Yes	$406,677,057	SAFSTOR	
1	Brown's Ferry Nuclear Power Station, Unit 1	BWR	3458	12/20/2033	$673,518,936	not provided	N/A	$756,675,357	$83,156,421	
1	Brown's Ferry Nuclear Power Station, Unit 2	BWR	3458	06/28/2034	$673,518,936	not provided	N/A	$750,995,772	$77,476,836	
1	Brown's Ferry Nuclear Power Station, Unit 3	BWR	3458	06/02/2036	$673,518,936	not provided	N/A	$751,873,341	$78,354,405	
1	Brunswick Steam Electric Plant, Unit 1	BWR	2923	09/08/2036	$650,105,422	not provided	N/A	$977,732,677	$327,627,255	
1	Brunswick Steam Electric Plant, Unit 2	BWR	2923	12/27/2034	$650,105,422	not provided	N/A	$967,774,599	$317,669,177	
2	Byron Station, Unit 1	PWR	3586	10/31/2024	$521,778,396	$628,047,000	Yes	$387,820,047	SAFSTOR	
2	Byron Station, Unit 2	PWR	3586	11/06/2026	$521,778,396	$682,306,000	Yes	$390,581,441	SAFSTOR	
1	Callaway Plant	PWR	3565	10/18/2024	$521,778,396	$617,214,000	No	$879,290,402	$357,512,006	
2	Calvert Cliffs Nuclear Power Plant, Unit 1	PWR	2737	07/31/2034	$487,346,187	$668,017,000	Yes	$401,687,027	SAFSTOR	
2	Calvert Cliffs Nuclear Power Plant, Unit 2	PWR	2737	08/13/2036	$487,346,187	$667,066,000	Yes	$543,567,871	SAFSTOR	
1	Catawba Nuclear Station, Unit 1	PWR	3411	12/05/2043	$516,435,786	not provided	N/A	$801,015,086	$284,579,300	
1	Catawba Nuclear Station, Unit 2	PWR	3411	12/05/2043	$516,435,786	not provided	N/A	$802,035,538	$285,599,752	
2	Clinton Power Station	BWR	3473	09/29/2026	$680,388,006	$960,325,000	Yes	$614,612,616	SAFSTOR	
1	Columbia Generating Station	BWR	3486	12/20/2023	$458,866,911	not provided	N/A	$613,153,226	$154,286,315	
1	Comanche Peak Steam Electric Station, Unit 1	PWR	3458	02/08/2030	$516,435,786	not provided	N/A	$602,722,407	$86,286,622	
1	Comanche Peak Steam Electric Station, Unit 2	PWR	3458	02/02/2033	$516,435,786	not provided	N/A	$698,676,777	$182,240,992	
1	Cook (Donald C.) Nuclear Power Plant, Unit 1	PWR	3304	10/25/2034	$517,182,770	not provided	N/A	$805,463,967	$288,281,197	
1	Cook (Donald C.) Nuclear Power Plant, Unit 2	PWR	3468	12/23/2037	$521,778,396	not provided	N/A	$799,364,478	$277,586,082	
1	Cooper Nuclear Station	BWR	2381	01/18/2034	$632,151,016	not provided	N/A	$981,626,836	$349,475,820	
1	Crystal River Nuclear Plant, Unit 3	PWR	2609	12/03/2016	$481,806,061	$753,717,000	Yes	$830,939,480	SAFSTOR	

2013 Decommissioning Funding Status Reports - Summary Table

Cat	Plant Name		MWth	Termination Date as of 3/31/2013	NRC Minimum Formula	Site Specific Cost Estimate	Certifying to Site Specific Cost Estimate (Note 1)	Projected Decommissioning Funding Amount including pro rata credit	Difference in NRC Minimum Formula and Projected Trust Fund Amount	How Potential Shortfall was resolved
2	Davis-Besse Nuclear Power Station	PWR	2772	04/22/2017	$493,918,411	not provided	N/A	$559,592,663	$65,674,252	
1	Diablo Canyon Nuclear Power Plant, Unit 1	PWR	3411	11/02/2024	$521,602,311	$1,062,300,000	No	$1,932,473,778	$1,410,871,468	
1	Diablo Canyon Nuclear Power Plant, Unit 2	PWR	3411	08/26/2025	$521,602,311	$1,100,400,000	No	$2,123,349,431	$1,601,747,120	
2	Dresden Nuclear Power Station, Unit 2	BWR	2957	12/22/2029	$658,277,915	not provided	N/A	$800,116,319	$141,838,404	
2	Dresden Nuclear Power Station, Unit 3	BWR	2957	01/02/2031	$658,277,915	not provided	N/A	$835,226,574	$176,948,658	
1	Farley (Joseph M.) Nuclear Plant, Unit 1	PWR	2775	06/25/2037	$488,990,912	not provided	N/A	$625,324,513	$136,333,601	
1	Farley (Joseph M.) Nuclear Plant, Unit 2	PWR	2775	03/31/2041	$488,990,912	not provided	N/A	$657,354,463	$168,363,551	
1	Fermi (Enrico) Atomic Power Plant, Unit 2	BWR	3430	03/20/2025	$1,070,497,506	not provided	N/A	$1,506,566,296	$436,068,791	
2	Fitzpatrick (James A.) Nuclear Power Plant	BWR	2536	10/17/2034	$650,386,339	not provided	N/A	$1,023,790,130	$373,403,791	
1	Fort Calhoun Station	PWR	1500	08/09/2033	$438,293,852	$502,386,000	No	$560,415,452	$122,121,599	
2	Ginna (Robert E.) Nuclear Power Plant	PWR	1775	09/18/2029	$458,325,698	$688,612,000	Yes	$453,730,180	SAFSTOR	
1	Grand Gulf Nuclear Station	BWR	4408	11/01/2024	$673,518,936	not provided	N/A	$964,780,344	$291,261,408	
1	Harris (Shearon) Nuclear Power Plant	PWR	2948	10/24/2046	$496,478,739	not provided	N/A	$1,642,521,180	$1,146,042,441	
1	Hatch (Edwin I.) Nuclear Plant, Unit 1	BWR	2804	08/06/2034	$644,762,172	not provided	N/A	$719,793,257	$75,031,086	
1	Hatch (Edwin I.) Nuclear Plant, Unit 2	BWR	2804	06/13/2038	$644,762,172	not provided	N/A	$704,478,716	$59,716,544	
2	Hope Creek Nuclear Power Station	BWR	3840	04/11/2026	$673,518,936	$832,555,600	No	$908,552,217	$235,033,281	
2	Indian Point, Unit 2	PWR	3216	09/28/2013	$522,460,949	$799,740,000	Yes	$466,274,081	SAFSTOR	
2	Indian Point, Unit 3	PWR	3216	12/12/2015	$522,460,949	not provided	N/A	$645,987,764	$123,526,814	
2	Kewaunee Nuclear Power Plant	PWR	1772	12/21/2033	$450,188,412	not provided	N/A	$941,649,557	$491,461,145	
2	LaSalle County Station, Unit 1	BWR	3489	04/17/2022	$680,388,006	$711,587,000	Yes	$505,349,976	SAFSTOR	
2	LaSalle County Station, Unit 2	BWR	3489	12/16/2023	$680,388,006	$697,445,000	Yes	$454,932,541	SAFSTOR	
1	Limerick Generating Station, Unit 1	BWR	3515	10/26/2024	$692,314,986	not provided	N/A	$699,411,803	$7,096,817	
1	Limerick Generating Station, Unit 2	BWR	3515	06/22/2029	$692,314,986	not provided	N/A	$850,711,140	$158,396,154	
1	McGuire (William B.) Nuclear Station, Unit 1	PWR	3411	06/12/2041	$516,435,786	not provided	N/A	$1,143,403,420	$626,967,635	
1	McGuire (William B.) Nuclear Station, Unit 2	PWR	3411	03/03/2043	$516,435,786	not provided	N/A	$824,038,930	$307,603,144	
2	Millstone Nuclear Power Station, Unit 2	PWR	2700	11/25/2045	$499,495,099	not provided	N/A	$745,340,936	$245,845,837	
2H	Millstone Nuclear Power Station, Unit 3	PWR	3411	09/08/2030	$531,054,936	not provided	N/A	$899,858,529	$368,803,593	

2013 Decommissioning Funding Status Reports - Summary Table

Cat	Plant Name		MWth	Termination Date as of 3/31/2013	NRC Minimum Formula	Site Specific Cost Estimate	Certifying to Site Specific Cost Estimate (Note 1)	Projected Decommissioning Funding Amount including pro rata credit	Difference in NRC Minimum Formula and Projected Trust Fund Amount	How Potential Shortfall was resolved
1	Monticello Nuclear Generating Plant	BWR	1775	09/08/2030	$604,663,341	not provided	N/A	$746,638,291	$141,974,951	
2	Nine Mile Point Nuclear Station, Unit 1	BWR	1850	08/22/2029	$618,724,467	$847,215,000	Yes	$646,786,494	SAFSTOR	
2H	Nine Mile Point Nuclear Station, Unit 2	BWR	3988	10/31/2046	$692,314,986	$982,696,000	Yes	$573,022,161	SAFSTOR	
1	North Anna Power Station, Unit 1	PWR	2893	04/01/2038	$494,098,216	not provided	N/A	$519,912,128	$25,813,912	
1	North Anna Power Station, Unit 2	PWR	2893	08/21/2040	$494,098,216	not provided	N/A	$521,708,623	$27,610,407	
1	Oconee Nuclear Station, Unit 1	PWR	2568	02/06/2033	$480,031,489	not provided	N/A	$664,273,354	$184,241,864	
1	Oconee Nuclear Station, Unit 2	PWR	2568	10/06/2033	$480,031,489	not provided	N/A	$639,419,349	$159,387,859	
1	Oconee Nuclear Station, Unit 3	PWR	2568	07/19/2034	$480,031,489	not provided	N/A	$808,837,775	$328,806,286	
2	Oyster Creek Nuclear Power Plant	BWR	1930	04/09/2029	$622,416,813	not provided	N/A	$1,207,128,805	$584,711,992	
2	Palisades Nuclear Plant	PWR	2565	03/24/2031	$484,866,301	not provided	N/A	$474,580,345	($10,285,956)	Decommissioning Trust Fund increased prior to DFS report submittal
1	Palo Verde Nuclear Generating Station, Unit 1	PWR	3990	06/01/2025	$521,602,311	not provided	N/A	$1,539,825,021	$1,018,222,710	
1	Palo Verde Nuclear Generating Station, Unit 2	PWR	3990	04/24/2026	$521,602,311	not provided	N/A	$1,732,333,610	$1,210,731,300	
1	Palo Verde Nuclear Generating Station, Unit 3	PWR	3990	11/25/2027	$521,602,311	not provided	N/A	$1,668,347,818	$1,146,745,508	
1	Peach Bottom Atomic Power Station, Unit 2	BWR	3514	08/08/2033	$692,314,986	not provided	N/A	$828,107,585	$135,792,600	
1	Peach Bottom Atomic Power Station, Unit 3	BWR	3514	07/02/2034	$692,314,986	not provided	N/A	$859,930,995	$167,616,010	
2H	Perry Nuclear Power Plant	BWR	3758	03/18/2026	$680,388,006	not provided	N/A	$667,270,346	($13,117,660)	Parent Company Guarantee
2	Pilgrim Station	BWR	2028	06/08/2012	$626,939,938	not provided	N/A	$1,145,131,918	$518,191,980	
2	Point Beach Nuclear Plant, Unit 1	PWR	1800	10/05/2030	$451,412,852	not provided	N/A	$454,122,504	$2,709,653	
2	Point Beach Nuclear Plant, Unit 2	PWR	1800	03/08/2033	$451,412,852	not provided	N/A	$448,936,466	($2,476,386)	Decommissioning Trust Fund increased prior to DFS report submittal
1	Praire Island Nuclear Plant, Unit 1	PWR	1650	08/09/2013	$444,853,352	not provided	N/A	$449,833,873	$4,980,521	
1	Praire Island Nuclear Plant, Unit 2	PWR	1650	10/29/2014	$444,853,352	not provided	N/A	$583,000,981	$138,147,629	
2H	Quad Cities Station, Unit 1	BWR	2957	12/14/2032	$658,277,915	not provided	N/A	$998,149,530	$339,871,614	
2H	Quad Cities Station, Unit 2	BWR	2957	12/14/2032	$658,277,915	not provided	N/A	$891,346,808	$233,068,893	
1	River Bend Station (Regulated)	BWR	3091	08/29/2025	$460,354,184	not provided	N/A	$539,844,932	$79,490,748	
2	River Bend Station (Non-Regulated)	BWR	3091	08/29/2025	$197,294,650	not provided	N/A	$353,127,725	$155,833,075	
1	Robinson (H.B.) Plant, Unit 2	PWR	2339	07/31/2030	$470,119,857	not provided	N/A	$862,122,219	$392,002,362	
1	Salem Nuclear Generating Station, Unit 1	PWR	3459	08/13/2016	$516,435,786	not provided	N/A	$907,449,545	$391,013,760	

2013 Decommissioning Funding Status Reports - Summary Table

Cat	Plant Name		MWth	Termination Date as of 3/31/2013	NRC Minimum Formula	Site Specific Cost Estimate	Certifying to Site Specific Cost Estimate (Note 1)	Projected Decommissioning Funding Amount including pro rata credit	Difference in NRC Minimum Formula and Projected Trust Fund Amount	How Potential Shortfall was resolved
1	Salem Nuclear Generating Station, Unit 2	PWR	3459	04/18/2020	$516,435,786	not provided	N/A	$873,077,144	$356,641,359	
1	San Onofre Nuclear Generating Station, Unit 2	PWR	3438	02/16/2022	$521,602,311	$1,214,400,000	No	$1,618,217,404	$1,096,615,094	
1	San Onofre Nuclear Generating Station, Unit 3	PWR	3438	11/15/2022	$521,602,311	$1,201,000,000	No	$1,833,874,102	$1,312,271,791	
2H	Seabrook Nuclear Power Station	PWR	3648	03/15/2030	$531,054,936	not provided	N/A	$633,118,755	$102,063,820	
1	Sequoyah Nuclear Plant, Unit 1	PWR	3455	09/17/2020	$516,435,786	not provided	N/A	$549,491,758	$33,055,973	
1	Sequoyah Nuclear Plant, Unit 2	PWR	3455	09/15/2021	$516,435,786	not provided	N/A	$635,783,576	$119,347,790	
1	South Texas Project, Unit 1	PWR	3853	08/20/2027	$516,435,786	not provided	N/A	$571,587,121	$55,151,335	
1	South Texas Project, Unit 2	PWR	3853	12/15/2028	$516,435,786	not provided	N/A	$663,908,809	$147,473,023	
1	St. Lucie Plant, Unit 1	PWR	3020	03/01/2036	$499,595,060	$534,825,000	No	$933,863,692	$434,268,631	
1	St. Lucie Plant, Unit 2	PWR	3020	04/06/2043	$499,595,060	$517,410,000	No	$932,793,072	$433,198,012	
1	Summer (Virgil C.) Nuclear Station	PWR	2900	08/06/2042	$494,401,192	not provided	N/A	$591,719,449	$97,318,257	
1	Surry Power Station, Unit 1	PWR	2546	05/25/2032	$479,079,280	not provided	N/A	$489,361,705	$10,282,425	
1	Surry Power Station, Unit 2	PWR	2546	01/29/2033	$479,079,280	not provided	N/A	$497,411,583	$18,332,303	
2H	Susquehanna Steam Electric Station, Unit 1	BWR	3952	07/17/2042	$692,314,986	not provided	N/A	$756,391,705	$64,076,720	
2H	Susquehanna Steam Electric Station, Unit 2	BWR	3952	03/23/2044	$692,314,986	not provided	N/A	$858,414,532	$166,099,547	
2	Three Mile Island Nuclear Station, Unit 1	PWR	2568	04/19/2034	$493,620,114	not provided	N/A	$869,526,182	$375,906,068	
1	Turkey Point Station, Unit 3	PWR	2644	07/19/2032	$483,320,939	not provided	N/A	$717,727,869	$234,406,930	
1	Turkey Point Station, Unit 4	PWR	2644	04/10/2033	$483,320,939	not provided	N/A	$787,230,244	$303,909,305	
2	Vermont Yankee Power Station	BWR	1912	03/21/2012	$621,586,035	not provided	N/A	$854,020,520	$232,434,485	
1	Vogtle (Alvin W.) Nuclear Plant, Unit 1	PWR	3625	01/16/2047	$516,435,786	not provided	N/A	$574,348,328	$57,912,543	
1	Vogtle (Alvin W.) Nuclear Plant, Unit 2	PWR	3625	02/09/2049	$516,435,786	not provided	N/A	$582,769,547	$66,333,762	
1	Waterford Generating Station, Unit 3	PWR	3716	12/18/2024	$516,435,786	not provided	N/A	$549,764,844	$33,329,059	
1	Watts Bar Nuclear Plant, Unit 1	PWR	3459	11/09/2035	$516,435,786	not provided	N/A	$567,205,467	$50,769,682	
1	Wolf Creek Generating Station	PWR	3565	03/11/2045	$521,778,396	not provided	N/A	$1,101,458,523	$579,680,127	

Definition of Terms:

Cat = Category - the licensee is categorized with respect to their qualification to use an external sinking fund as its only financial assurance method. The circumstances necessary to achieve qualification are given in 10 CFR 50.75€(1)(ii). In general, the licensee may use an external sinking fund if it is allowed to collect funds for decommissioning through ratemaking regulation or non-bypassable charges.

Category 1 - Licensees are authorized to collect funds for decommissioning through ratemaking regulation or non-bypassable charges. Licensees who set their own rates are in this category. Investor owned utility licensees normally are in Category 1. Some merchant plant licensees may be placed in Category 1 if they are eligible to collect non-bypassable charges.

Category 2 - Licensees do not have access to funds from ratepayers or non-bypassble charges. Merchant plants normally fall into this category.

Category 2H - Licensees sell the output of their plant in both utility and merchant markets, and collect only part of the cost of decommissioning through ratemaking regulation or non-bypassble charges.

SAFSTOR - a licensee provided a site-specific cost estimate assuming a period of safe storage of the site before completing decommissioning

Notes:

Note 1 - A licensee is allowed to certify to a site-specific cost estimate as long as that amount is equal to or greater than the amount calculated in 10 CFR 50.75(c).

NUREG-0586, Supplement 1
Volume 1

Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities

Supplement 1

Regarding the Decommissioning of Nuclear Power Reactors

Main Report, Appendices A through M

Final Report

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555-0001

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NUREG-0586, Supplement 1
Volume 1

Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities

Supplement 1

Regarding the Decommissioning of Nuclear Power Reactors

Main Report, Appendices A through M

Final Report

Manuscript Completed: October 2002
Date Published: November 2002

Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Abstract

This document is a supplement to the U.S. Nuclear Regulatory Commission (NRC) document *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* issued in 1988 (NUREG-0586, referred to here as the 1988 Generic Environmental Impact Statement [GEIS]). This Supplement was prepared because of technological advances in decommissioning operations, experience gained by licensees, and changes made to NRC regulations since the 1988 GEIS.

This Supplement updates the information provided in the 1988 GEIS. It is intended to be used to evaluate environmental impacts during the decommissioning of nuclear power reactors as residual radioactivity at the site is reduced to levels that allow for termination of the NRC license. This Supplement addresses only the decommissioning of nuclear power reactors licensed by the NRC. It updates the sections of the 1988 GEIS relating to pressurized water reactors, boiling water reactors, and multiple reactor stations. It goes beyond the 1988 GEIS to explicitly consider high-temperature gas-cooled reactors and fast breeder reactors. This document can be considered a stand-alone document for power reactor facilities such that readers should not need to refer back to the 1988 GEIS. The environmental impacts described in this Supplement supercede those described for power reactor facilities in the 1988 GEIS.

The scope of this Supplement is based on the decommissioning activities performed to remove radioactive materials from structures, systems, and components from the time that the licensee certifies that it has permanently ceased power operations until the license is terminated. The scope of the document was determined through public scoping meetings and meetings with other Federal agencies and the nuclear industry. An evaluation process was then developed to determine environmental impacts from nuclear power reactor facilities that are being decommissioned. The evaluation process involved determining the specific activities that occur during reactor decommissioning and obtaining data from site visits and from licensees at reactor facilities currently being decommissioned. The data obtained from the sites were analyzed and then evaluated against a list of variables that defined the parameters for facilities that are currently operating but which will one day be decommissioned. This evaluation resulted in a range of impacts for each environmental issue that may be used for comparison by licensees that are or will be decommissioning their facilities.

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Executive Summary

This document is a supplement to the U.S. Nuclear Regulatory Commission (NRC) document *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities,* issued in 1988 (NUREG-0586, referred to hereafter as the 1988 Generic Environmental Impact Statement [GEIS]).[a] As a supplement, this document considers the technological advances in decommissioning, the experience gained by licensees, and changes made to NRC regulations since the 1988 GEIS. The information from the 1988 GEIS that is still current and applicable to permanently shut down and currently operating commercial nuclear power reactors is included here. This Supplement is intended to be used to evaluate environmental impacts during the decommissioning of nuclear power reactors as residual radioactivity at the site is reduced to levels that allow for termination of the NRC license.

The NRC elected to supplement the GEIS:

(1) to further the purposes of the National Environmental Policy Act (NEPA)

(2) to update the information in the GEIS

(3) to provide additional information to the public on decommissioning activities

(2) to establish an envelope of environmental impacts that could be associated with decommissioning activities.

Unlike the 1988 GEIS, which took a broad look at decommissioning of a variety of sites and activities, this Supplement addresses only nuclear power reactors licensed by the NRC. It updates the sections of the 1988 GEIS relating to pressurized water reactors, boiling water reactors, and multiple reactor stations. It goes beyond the 1988 GEIS and considers the existing permanently shut down high-temperature gas-cooled reactor and fast breeder reactor. It does not include research and test reactors or the power reactor facilities that have been involved in a significant accident resulting in large-scale contamination of structures, systems, and components (SSCs). It also does not include other types of fuel-cycle facilities, such as fuel-reprocessing plants or small mixed oxide fuel-fabrication plants.

The intent of this Supplement is to consider in a comprehensive manner all aspects related to the radiological decommissioning of nuclear reactor facilities by incorporating updated information, regulations, and analyses. Since the 1988 GEIS was written, the NRC and the industry have gained substantially more nuclear power facility decommissioning experience. Based on the number of reactors shut down and the date that they permanently ceased

(a) The GEIS is considered "generic" in that it evaluates environmental impacts from decommissioning activities common to a number of nuclear power facilities.

operations, over 200 facility-years' worth of decommissioning experience have accumulated since the NRC published the 1988 GEIS. Currently, there are 19 commercial power reactor facilities in the decommissioning process. This includes nine that permanently ceased operations after the NRC published the 1988 GEIS. Since the 1988 GEIS, there are three facilities that have completed decommissioning and terminated their licenses. There are also new technologies and approaches applicable to decommissioning that the 1988 GEIS does not address. The regulations for decommissioning reactors have also undergone significant changes since the 1988 GEIS.

Scope of the Supplement

The content of this Supplement was initially defined by the scope of the 1988 GEIS and was modified based on current decommissioning regulations, input received during four public scoping meetings, letters and comments received during the scoping period, and meetings between the NRC and the U.S. Environmental Protection Agency (EPA) and the Council on Environmental Quality (CEQ). The public comments received during the scoping process that were considered to be with the scope of the environmental review are provided in Volume 2 Appendix N. The NRC staff published for comment Supplement 1 to the GEIS in October 2001. Public meetings in San Francisco, California, Boston Massachusetts, Chicago, Illinois and Atlanta, Georgia were held in December, 2001 to describe the preliminary results of the NRC environmental review, to answer questions, and to provide members of the public with information to assist them in formatting comments on the draft Supplement. All comments received on the draft Supplement were considered by the staff in developing the final document and are presented in Appendices O and P.

The scope of this Supplement is based on the decommissioning activities performed to remove radioactive materials from SSCs from the time that the licensee certifies that it has permanently ceased power operations until the license is terminated. As a result, the activities performed before permanent cessation of operations (except for decommissioning planning) or impacts that are related to the decision to permanently cease operations (for example, the impact from the loss of generation capacity) are outside the scope of this document.

The Commission defines decommissioning as "to remove a facility or site safely from service and reduce residual radioactivity to a level that permits (1) Release of the property for unrestricted use and termination of the license; or (2) Release of the property under restricted conditions and termination of the license." The staff has included activities that are directly related to the removal of radioactive material from the facility or that must be performed in order to facilitate the removal of contaminated SSCs, as well as the activities and impacts related to the removal of uncontaminated SSCs (such as the intake structure or cooling towers) that were required for the operation of the reactor.

The decommissioning process continues until the licensee requests termination of the license and demonstrates that radioactive material has been removed to the levels that permit

termination of the NRC license. At that point, the NRC no longer has jurisdiction over the site and the owner of the site is no longer subject to NRC regulations. As a result, activities performed after license termination and the resulting impacts are outside the scope of this Supplement. These activities may include any non-NRC required monitoring, site restoration (grading, planting of vegetation, etc.), continued dismantlement (removal of uncontaminated structures or those that have been radiologically decontaminated), or continued use of the site for activities such as power production using natural gas, oil, or coal.

Any potential radiological impacts following license termination that are related to activities performed during the decommissioning period are not considered in this Supplement. Those impacts are covered by the *Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities* (NUREG-1496). Nonradiological impacts following license termination that are related to activities performed during the decommissioning period are considered in this Supplement.

Levels of Significance and Applicability of Environmental Impacts

This Supplement provides a measure of (a) the significance and severity of potential environmental impacts and (b) the applicability of these impacts to a variety of plants both permanently shut down and operating. The significance of the environmental impacts is described as either SMALL, MODERATE or LARGE. The applicability of these impacts to a variety of plants is categorized as either generic or site-specific.

Levels of Significance: For decommissioning, the staff is using a standard of significance derived from the CEQ terminology for "significantly" (40 CFR 1508.27, which considers "context" and "intensity"). The NRC has defined three significance levels: SMALL, MODERATE, and LARGE.

SMALL - Environmental impacts are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts in this Supplement, the NRC has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

MODERATE - Environmental impacts are sufficient to alter noticeably but not to destabilize important attributes of the resource.

LARGE - Environmental impacts are clearly noticeable and are sufficient to destabilize important attributes of the resource.

The discussion of each environmental issue in this Supplement includes an explanation of how the significance level was determined. In determining the significance level, the NRC staff assumed that ongoing mitigation measures would continue (including those mitigation

measures implemented during plant construction and/or operation) during decommissioning, as appropriate. Benefits of additional mitigation measures during or after decommissioning are not considered in determining significance levels.

Applicability: In addition to determining the significance of environmental impacts, this Supplement includes a determination of whether the analysis of the environmental issues could be applied to all plants, and whether additional mitigation measures would be warranted. An environmental issue may be assigned to one of two categories:

- Generic - For each environmental issue, the analysis reported in this Supplement shows the following:

  (1) Environmental impacts associated with the issue have been determined to apply either to all plants, or for some issues to plants of a specific size, specific location or having a specific type of cooling system or site characteristics, and

  (2) A single significance level (i.e., SMALL, MODERATE, or LARGE) has been assigned to the impacts, and

  (3) Mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely not to be sufficiently beneficial to warrant implementation.

- Site-specific - For each environmental issue that was determined to be site-specific, the analysis reported in this Supplement has shown that one or more of the generic criteria was not met. Therefore, additional plant-specific review is required. An example of a site-specific issue is threatened and endangered species.

Use and Development of this Supplement

This Supplement can be used by the public to understand the decommissioning process, the activities performed during decommissioning, and the potential environmental impacts resulting from these activities. It identifies activities that can be bounded by a generic evaluation. Licensees can rely on the information in this Supplement as a basis for meeting the requirements in 10 CFR 50.82(a)(6)(ii). This requirement states that the licensee must not perform any decommissioning activity that causes any significant environmental impact not previously reviewed. The NRC staff will also rely on this Supplement as a basis for determining if anticipated decommissioning impacts require an additional review.

The staff first created an initial list of environmental issues and activities that this Supplement should address. The initial list of environmental issues was developed from issues (such as air

quality, aquatic ecology, and radiological impacts) identified in the 1988 GEIS and in the list specified in 10 CFR Part 51, Subpart A, Appendix B, for license renewal. This list was used because it represents the potential impacts associated with nuclear power facilities. The initial list of decommissioning activities was modified based on experience, public participation in the scoping process, site visits to six facilities currently being decommissioned, and meetings with EPA and CEQ. After compiling the issue and activity lists, the staff assessed which activities might have environmental impacts for each of the issues. The next step was to identify the variables that might affect the decommissioning impact for a specific issue and activity. For example, the proximity of the plant to a barge slip or railroad might affect the licensee's decision to remove the steam generator or other large components intact and ship them to a waste site. If the barge slip needs additional dredging, or an additional railroad line needs to be installed, then the environmental impacts may change.

The analyses in this Supplement include data from both operating and decommissioning facilities in order to appropriately span the range of impacts that could be expected. Data from decommissioning facilities was used to determine whether the potential impacts from decommissioning activities for the various issues are generic or site-specific. Data from operating facilities were used to ensure that this Supplement will be valid for all commercial nuclear power reactors.

Alternatives

The alternative to the action of decommissioning is not to decommission the facility. The option to restart the reactor is not considered to be an alternative to decommissioning because the decision to permanently cease operation prevents the licensee from operating the reactor without a significant safety and environmental review by the NRC staff.

The alternative to decommissioning at the end of the licensing period is a "no action" alternative, implying that a licensee would simply abandon or leave a facility after ceasing operations. NRC regulations do not allow the option of not decommissioning. Once the facility permanently ceases operation, if the licensee does not conduct decommissioning activities to an extent that meets the license termination criteria in 10 CFR Part 20, Subpart E, then the license will not be terminated (although the licensee will not be authorized to operate the reactor). The licensee will be required to comply with the necessary requirements for the operating license. As a result, the environmental impacts for maintaining the nuclear reactor facility will be considered to be in the bounds of the appropriate, previously issued Environmental Impact Statements. Under NRC regulations, the original operating license for a nuclear power plant is issued for up to 40 years. The license may be renewed for periods of up to 20 years if NRC requirements are met. However, at the end of the licensing period (whether it has been extended or not), the regulations require that the facility be decommissioned.

Conclusions

Table ES-1 presents each evaluated environmental issue and identifies whether the issue is considered generic or site-specific. If the issue is considered generic, then it is assigned a significance level of either SMALL, MODERATE or LARGE. Of the environmental issues assessed, most of the impacts are generic and SMALL for all plants regardless of the activities and identified variables (see Appendix E for a list of the variables). The two issues determined to be site-specific are threatened and endangered species and environmental justice. Four issues are considered to be conditionally site-specific.

- land use involving offsite areas to support decommissioning activities
- aquatic ecology for activities beyond the operational area
- terrestrial ecology for activities beyond the operational area
- cultural and historic resources for activities beyond the operational area with no current cultural and historic resource survey.

The operational area is defined as the portion of the plant site where most or all of the site activities occur, such as reactor operation, materials and equipment storage, parking, substation operation, facility service, and maintenance. This includes areas within the protected area fences, the intake, discharge, cooling, and associated structures as well as surrounding paved, graveled, maintained landscape, or other maintained areas.

Licensees undergoing or planning decommissioning of a commercial nuclear power reactor can use this Supplement in support of their evaluation of the environmental consequences from decommissioning. The impacts identified in this Supplement are designed to span the range of impacts from all plants that are currently permanently shut down as well as the plants that are currently operating, including the plants that have or may renew their licenses beyond the original 40-year license; a renewed license can be issued for a period not to exceed 20 years beyond the expiration of the operating license. When planning a specific decommissioning activity, licensees that fall within the bounds of the impacts, as described in Chapter 4, may proceed with the activity with no further analysis. However, if the planned activity could result in environmental impacts greater than those predicted by this supplement, then the activity cannot be performed until the licensee performs a site-specific analysis of the activity. Depending on the results of the site-specific evaluation, the staff may determine that it is appropriate to consult with another agency (such as the U.S. Fish and Wildlife Service or a State Historic Preservation Office). If the activity would result in an impact that is outside the bounds of the GEIS or other environmental assessments, the licensee would be required to submit a license-amendment request.

Table ES-1. Summary of the Environmental Impacts from Decommissioning Nuclear Power Facilities

Issue	Generic	Impact
Onsite/Offsite Land Use		
- Onsite land use activities	Yes	SMALL
- Offsite land use activities	No	Site-specific
Water Use	Yes	SMALL
Water Quality		
- Surface water	Yes	SMALL
- Groundwater	Yes	SMALL
Air Quality	Yes	SMALL
Aquatic Ecology		
- Activities within the operational area	Yes	SMALL
- Activities beyond the operational area	No	Site-specific
Terrestrial Ecology		
- Activities within the operational area	Yes	SMALL
- Activities beyond the operational area	No	Site-specific
Threatened and Endangered Species	No	Site-specific
Radiological		
- Activities resulting in occupational dose to workers	Yes	SMALL
- Activities resulting in dose to the public	Yes	SMALL
Radiological Accidents	Yes	SMALL
Occupational Issues	Yes	SMALL
Cost	NA[a]	NA
Socioeconomic	Yes	SMALL
Environmental Justice	No	Site-specific
Cultural and Historic Resource Impacts		
- Activities within the operational areas	Yes	SMALL
- Activities beyond the operational areas	No	Site-specific
Aesthetics	Yes	SMALL
Noise	Yes	SMALL
Transportation	Yes	SMALL
Irretrievable Resources	Yes	SMALL

(a)A decommissioning cost assessment is not a specific National Environmental Policy Act (NEPA) requirement. However, an accurate decommissioning cost estimate is necessary for a safe and timely plant decommissioning. Therefore, this Supplement includes a decommissioning cost evaluation, but the cost is not evaluated using the environmental significance levels nor identified as a generic or site-specific issue.

Abbreviations/Acronyms

μGy	microGray(s)
μSv	microSieverts
ac	acre(s)
AEA	Atomic Energy Act of 1954
AEC	U.S. Atomic Energy Commission
ALI	annual limits on intake
ALARA	as low as reasonably achievable
ANPR	advance notice of proposed rulemaking
BLM	Bureau of Land Management
BMP	best management practice
Bq	Bequerel(s)
BWR	boiling water reactor
C	Celsius
CAA	Clean Air Act
CDE	committed dose equivalent
CEDE	committed effective dose equivalent
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
Ci	Curie
CWA	Clean Water Act
DAC	derived air concentration
dB	decibel
dBA	A-weighted sound levels
dBC	C-weighted sound levels
DBA	design basis accident
DDREF	dose or dose rate effectiveness factor
DE	dose equivalent
DNL	day-night average sound level
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation

EA	environmental assessment
EDE	effective dose equivalent
EIS	environmental impact statement
EJ	environmental justice
EPA	U.S. Environmental Protection Agency
ER	environmental report
ESA	Endangered Species Act of 1973
ES&H	environment, safety and health
F	Fahrenheit
FAA	Federal Aviation Administration
FBR	fast breeder reactor
FES	final environmental statement
FHA	Federal Housing Administration
FR	Federal Register
FSAR	Final Safety Analysis Report
ft	foot/feet
FWPCA	Federal Water Pollution Control Act (also known as the Clean Water Act of 1977)
FWS	U.S. Fish and Wildlife Service
gal.	gallon(s)
GEIS	Generic Environmental Impact Statement
gpd	gallons per day
gpm	gallons per minute
GTCC	Greater-than-Class-C (waste)
Gy	gray(s)
ha	hectare(s)
HDA	high decommissioning activity
HEPA	high-efficiency particulate air (filter)
HLW	high-level waste
h	hour
HTGR	high-temperature gas-cooled reactor
HUD	U.S. Department of Housing and Urban Development
HVAC	heating, ventilation, and air conditioning
IAEA	International Atomic Energy Agency
in.	inch(es)
I&C	instrumentation and control

ICRP	International Commission on Radiological Protection
ISFSI	independent spent fuel storage installation
kg	kilogram(s)
km	kilometer(s)
kV	kilovolt(s)
kWh	kilowatt hour(s)
L	liter(s)
LDA	low-decommissioning activity
LER	licensee event report
LET	linear energy transfer
LLW	low-level waste
LOS	level of service
LRA	license renewal application
LTP	license termination plan
LWR	light water reactor
m	meter(s)
m^3/d	cubic meters per day
m^3/s	cubic meters per second
MARSSIM	Multi-agency Radiation Survey and Site Investigation Manual, NUREG-1575
MBTA	Migratory Bird Treaty Act of 1918
mi	mile(s)
mGy	milliGray(s)
MPC	maximum permissible concentrations
mrad	millirad(s)
mrem	millirem(s)
MRS	monitored retrievable storage
mSv	milliSievert(s)
MTHM	metric tonnes of heavy metal
MT	metric ton(s) (or tonne[s])
MTU	metric ton(s)-uranium
MW	megawatt(s)
MWd/MTU	megawatt-days per metric ton of uranium
MW(e)	megawatt(s) electric
MW(t)	megawatt(s) thermal
MWh	megawatt hour(s)

NA	not applicable
NAS	National Academy of Sciences
NBS	National Bureau of Standards

NCRP	National Council on Radiation Protection and Measurements
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act of 1969
NHPA	National Historic Preservation Act of 1966
NIST	National Institute of Standards and Technology
NMFS	National Marine Fisheries Service
NO_x	nitrogen oxide(s)
NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NWPA	Nuclear Waste Policy Act of 1982
ODCM	Offsite Dose Calculation Manual
OSHA	Occupational Safety and Health Administration
PAG	protective action guide
PCBs	polychlorobiphenyls
PEL	permissible exposure limit
POL	possession-only license
PPE	personal protective equipment
PSDAR	post-shutdown decommissioning activities report
PV	pressure vessel
PWR	pressurized water reactor
QA/QC	quality assurance/quality control
RCRA	Resource Conservation and Recovery Act of 1976
RCS	reactor coolant system
ROW	right-of-way/rights-of-way
RPV	reactor pressure vessel
SARA	Superfund Amendments and Reauthorization Act
SHPO	State Historic Preservation Officer
SI	Systeme Internationale (international system of units)
SO_2	sulfur dioxide
SO_x	sulfur oxide(s)
SSCs	structures, systems, and components
Sv	sievert(s)

TEDE	total effective dose equivalent
THPO	Tribal Historic Preservation Officer
UNSCEAR	United Nations Scientific Committee on The Effects of Atomic Radiation
USC	United States Code
USFWS	U.S. Fish and Wildlife Service
VOC	volatile organic compound
VRM	Visual Resource Management (system)
wk	week(s)
YNPS	Yankee Nuclear Power Station
yr	year(s)

1.0 Introduction

1.1 Purpose and Need for This Supplement

This document supplements the *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* (NRC 1988), issued in 1988 (NUREG-0586, referred to hereafter as the 1988 GEIS) for power reactor facilities. This Supplement updates information provided in the 1988 GEIS by considering technological advances in decommissioning activities gained since 1988 and changes in U.S. Nuclear Regulatory Commission (NRC) regulations and, where appropriate, other agency regulations. The NRC has adopted the following definition of the purpose and need of this Supplement:

> The purpose and need are to provide an analysis of environmental impacts from decommissioning activities that can be treated generically so that decommissioning activities for commercial nuclear power reactors conducted at specific sites will be bounded, to the extent practicable, by this and appropriate previously issued environmental impact statements.

This Supplement is intended to be used to evaluate environmental impacts during the decommissioning of nuclear power facilities as residual radioactivity at the site is reduced to levels that allow for termination of the NRC license. This Supplement can be considered a stand-alone document for power reactor facilities such that readers should not need to refer back to the 1988 GEIS. The environmental impacts described in this Supplement supercede those described in the 1988 GEIS for power reactor facilities.

The NRC elected to supplement the 1988 GEIS:

(1) to further the purposes of the National Environmental Policy Act (NEPA)

(2) to update the information in the 1988 GEIS

(3) to provide additional information to the public on decommissioning activities

(4) to establish an envelope of environmental impacts associated with decommissioning activities.

Unlike the 1988 GEIS, this Supplement covers only reactor facilities licensed by the NRC for commercial power production. It updates the sections of the 1988 GEIS relating to pressurized water reactors, boiling water reactors, and multiple reactor stations. It goes beyond the 1988 GEIS and considers the permanently shut down high-temperature gas-cooled reactors and fast

breeder reactors. It does not cover research and test reactors or power reactor facilities that have been involved in a significant accident resulting in large-scale contamination of structures, systems, and components (SSCs). It also does not cover other types of fuel-cycle facilities, such as fuel-reprocessing plants or small mixed oxide fuel-fabrication plants.

This Supplement incorporates updated information, regulations, and analyses. Since the 1988 GEIS was written, the NRC and the industry have gained over 200 facility-years' worth of additional decommissioning experience. Currently, there are 19 nuclear power reactor facilities in the decommissioning process. This includes nine that permanently ceased operations after the NRC published the 1988 GEIS. Since the 1988 GEIS, three facilities have completed decommissioning and terminated their licenses: Pathfinder, Shoreham, and Fort St. Vrain. This Supplement addresses new decommissioning technologies and approaches that the 1988 GEIS did not address. Also, the decommissioning regulations have changed since the 1988 GEIS.

1.2 Process Used to Determine Scope of This Supplement

The content of this Supplement was initially defined by the scope of the 1988 GEIS and was modified based on current decommissioning regulations, inputs from the scoping process and the outcome of meetings between the NRC, the U.S. Environmental Protection Agency (EPA), and the Council on Environmental Quality (CEQ).

Four public scoping meetings were held between April and June 2000 as part of the scoping process. During the meetings, the NRC outlined the GEIS revision process and accepted comments regarding the scope of this Supplement. In addition to comments obtained during the scoping meetings, the NRC received 12 letters from industry groups, other interested organizations, and private citizens. A total of 397 comments were provided during the scoping process. The staff reviewed the comments and categorized them as either relevant to this Supplement or outside of its intended scope. The staff prepared and issued a scoping summary report on April 17, 2001 (NRC 2001), that summarized the comments and NRC responses to the comments. Appendix N is an extraction of comments from the scoping summary report that were considered to be within the scope of the environmental review. The NRC staff published for comment draft Supplement 1 to the GEIS in October 2001. Public meetings in San Francisco, California, Boston, Massachusetts, Chicago, Illinois and Atlanta, Georgia, were held in December 2001, to describe the preliminary results of the NRC environmental review, to answer questions, and to provide members of the public with information to assist them in formatting comments on the draft Supplement. All comments received on the draft Supplement were considered by the staff in developing the final document. Appendix O provides a compilation of comments received on the draft Supplement and staff responses to the comments. Originally, the staff planned to publish the scoping

summary and the response to comments in Appendices A and B of this report. However, due to the length of these two appendices, the staff decided to publish these two appendices and the appendix containing the transcripts and comment letters in a second volume. In addition to the scoping meetings, meetings were held with EPA and CEQ between February and November 2000 to obtain input on the scope of the environmental review.

Site visits were conducted by the NRC staff and its contractor at six nuclear reactor facilities that are in various stages of decommissioning. The site visits were conducted to obtain information and to familiarize the NRC team with the current types of activities conducted and the resulting impacts during decommissioning. In addition to the site visits, the Nuclear Energy Institute arranged access to additional site-specific decommissioning data. In addition to the six sites visited, data was received for three other nuclear power reactor facilities.

Information used in this report was also obtained from docketed material, such as post-shutdown decommissioning activity reports (PSDARs), effluent release reports, license termination plans (LTPs), and decommissioning funding plans.

1.3 Scope of This Supplement

Except for decommissioning planning activities, this Supplement considers only activities that occur following certification that fuel has been removed from the reactor. Figure 1-1 illustrates the decommissioning process. Licensee decommissioning activities are listed in the top part of the timeline. Regulatory activities are summarized by the lower part of the timeline. This section discusses licensee decommissioning activities that are within scope and also explains why some activities and impacts are not in scope for this Supplement. Table 1-1 briefly lists decommissioning activities that are within and outside the scope of this Supplement. Additional discussion of the out-of-scope activities is provided in Appendix D.

Impacts related to the decision to permanently cease operations are outside the scope of this Supplement. This includes impacts that result directly and immediately from the act of permanently ceasing operations, regardless of when or why the decision was made. For example, when a reactor ceases operation, the flow of warmer water into the canal, lake, or river that receives the plant's thermal discharges is stopped, and this may impact the organisms in the vicinity of the thermal outfall. However, this impact is not within the scope of this Supplement because it is essentially a restoration of the existing conditions.

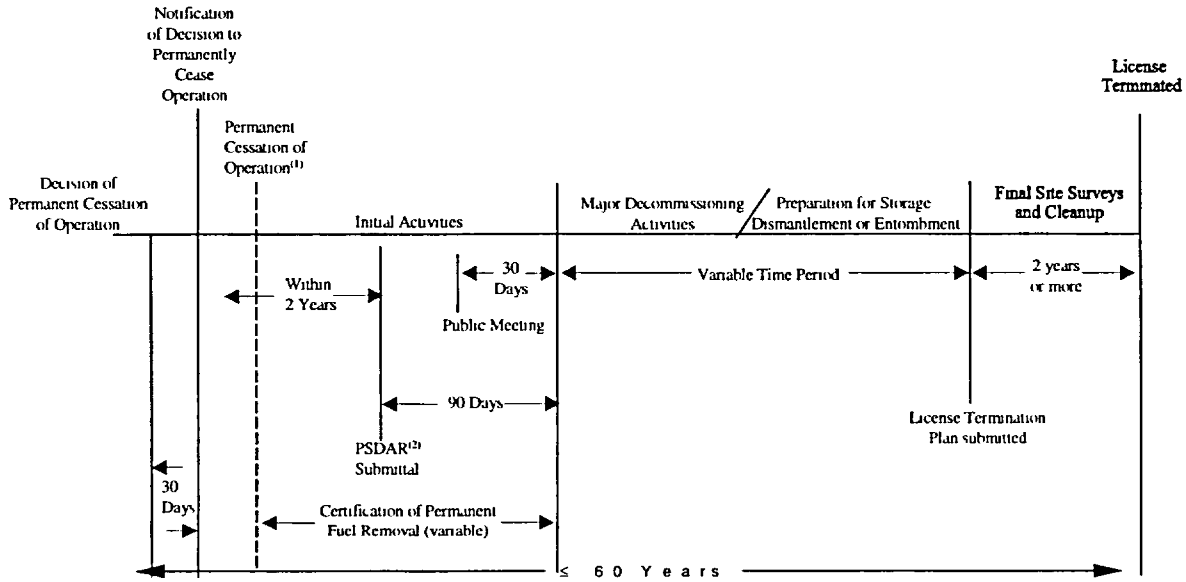


Figure 1-1.
Decommissioning Timeline

(1) The cessation of operations may occur before, concurrent with, or following the certification to permanently cease operations.
(2) The PSDAR may be submitted before permanent cessation of operations.

The licensee may declare or certify the date for permanent cessation of operations prior to the end of the license term and while still operating. In such cases, the decommissioning planning activities prior to shutdown and activities and impacts that occur following the actual shutdown of the facility are within the scope of this Supplement. In some circumstances, the licensee may not operate the facility for a period of many years without certifying that they have permanently ceased power operations. In these cases, the activities occurring before the certification is completed would be considered part of the operational phase of the facility and would be within the scope of the site-specific environmental impact statement (EIS) that covers reactor operations but are outside the scope of this Supplement.

The NRC definition for *decommission* in 10 CFR 50.2 is "to remove a facility or site safely from service and reduce residual radioactivity to a level that permits (1) Release of the property for unrestricted use and termination of the license; or (2) Release of the property under restricted conditions and termination of the license." This Supplement is not limited only to activities directly related to the removal of radioactive material from facilities or that must be performed to facilitate removal of contaminated SSCs. The staff has included activities and impacts related

to removing uncontaminated SSCs that were required for reactor operation, such as the intake structure or cooling towers. Including uncontaminated SSCs in this Supplement is consistent with an expectation under NEPA that all impacts associated with an activity and that public concerns about the scope of the review be considered.

Various activities that are performed in conjunction with decommissioning are not considered within the scope of this Supplement, but are reviewed and regulated by the NRC under other licenses. These activities include

- independent spent fuel storage installation (ISFSI) construction, maintenance, and decommissioning – An ISFSI can be operated and decommissioned either under the same license that is used for the operating or decommissioning facility called a general license under 10 CFR Part 50, or under a specific license under 10 CFR Part 72. If a licensee chose to operate the ISFSI under a Part 50 license, it could choose to continue to maintain their Part 50 license, or seek a site -specific 10 CFR Part 72 license for the ISFSI, thus allowing termination of the Part 50 license and the end of the reactor decommissioning process. The NRC staff would also be required to conduct an environmental assessment of the licensee's request for a site-specific 10 CFR Part 72 license.

- spent fuel storage and maintenance – The Commission has independently, in a separate proceeding (the Waste Confidence Proceeding), made a finding that there is

> reasonable assurance that, if necessary, spent fuel generated in any reactor can be stored safely and without significant environmental impacts for at least 30 years beyond the licensed life for operation (which may include the term of a revised license) of that reactor at its spent fuel storage basin, or at either onsite or offsite independent spent fuel storage installations. (54 FR 39767)

The Commission has committed to review this finding at least every 10 years. In its most recent review, the Commission concluded that experience and developments since 1990 were not such that a comprehensive review of the Waste Confidence Decision was necessary at that time (64 FR 68005). Accordingly, the Commission reaffirmed its findings of insignificant environmental impacts cited above. This finding is codified in the Commission's regulations at 10 CFR 51.23(a). The staff relies on the Waste Confidence Rule, but has elected to include in this Supplement information related to the storage and maintenance of fuel in a spent fuel pool for completeness.

Table 1-1. Activities and Impacts Within or Outside the Scope of This Supplement

In Scope

- Activities performed to remove the facility from service from the time that the licensee certifies that the facility has permanently ceased operations
- Activities (and the resulting impacts) performed in support of radiological decommissioning, including decontamination and dismantlement of radioactive structures and any activities required to support the decontamination and dismantlement process
- Activities performed in support of dismantlement of nonradiological structures, systems, and components (SSCs) required for the operation of the reactor, such as diesel generator buildings and cooling towers
- Activities performed up to license termination and their resulting impacts as provided in the definition of decommissioning Nonradiological impacts occurring after license termination from activities conducted during decommissioning
- Activities related to release of the facility
- Human health impacts from radiological and nonradiological decommissioning activities
- Activities related to preparing the facility for entombment

Out of Scope[a]

- Activities and the resulting impacts (other than planning activities) that are performed before permanent cessation of operation is certified
- Radiological impacts following license termination
- Activities (and the resulting impacts) performed to dismantle structures on the site that are not radiologically contaminated and were not required for operation of the reactor (e.g., training building and administration building)
- Activities performed to support installation of alternate energy-generating facilities during or following the decommissioning process
- Site restoration activities performed during or after the decommissioning process
- Activities (and their impacts) performed after license termination, such as
  - any additional non-NRC required monitoring to evaluate radiological impacts
  - site restoration
  - continued use of site for power production or other activities
- Activities performed at facilities that are separately licensed or regulated
  - independent spent fuel storage installation (ISFSI) construction, maintenance, or decommissioning
  - interim storage of Greater-than-Class-C Waste
  - spent fuel storage,[b] maintenance, and disposal on or away from a reactor location
  - low-level waste (LLW) disposal at a licensed LLW site or treatment at compactor facilities
- Activities to install engineered barriers and institutional controls for restricted release
- Public perceptions and psychological impacts
- Activities at facilities that have been permanently shut down by a major accident
- Issues related to the ENTOMB option after the facility begins the entombment period

(a) A detailed discussion of the reasons for determining that activities are out of scope can be found in Appendix D.
(b) As discussed in the text, the staff relies on the Waste Confidence Decision Review (54 FR 39767 and 64 FR 68005) but has chosen to include information related to the storage and maintenance of fuel in a spent fuel pool for completeness in this Supplement.

- spent fuel transport and disposal away from the reactor location – Transportation of spent fuel and other high-level nuclear wastes is governed by regulations in 10 CFR Part 71, "Packaging and Transportation of Radioactive Material." Disposal of spent fuel and high-level wastes are governed by the Nuclear Waste Policy Act (NWPA) of 1982, as amended, which defined the goals and structure of a program for permanent, deep geologic repositories for the disposal of high-level radioactive waste and nonreprocessed spent fuel. Under this Act, the U.S. Department of Energy (DOE) is responsible for developing permanent disposal capacity for spent fuel and other high-level nuclear wastes. Title 10 CFR Part 60 contains rules governing the licensing to receive and possess source, special nuclear, and by-product material at a geological repository operations area that is sited, constructed, or operated in accordance with the NWPA. However, the Commission issued the final rule to supercede the generic criteria in 10 CFR Part 60 for disposal at a geological repository with specific criteria in 10 CFR Part 63, issued on November 2, 2001 (66 FR 55732).

- LLW disposal at a licensed LLW site or treatment of LLW at compactor facilities – Regulations related to LLW disposal are in 10 CFR Part 61 and 10 CFR Part 20, Subpart K. A final GEIS supporting the regulations in 10 CFR Part 61, "Final Generic Environmental Impact Statement for 10 CFR Part 61" was published as NUREG-0945 (NRC 1982).

A further description of these activities and the basis for not including them in the scope of this supplement is in Appendix D.

The decommissioning process continues until the licensee requests termination of the license and demonstrates that radioactive material has been removed to levels that permit termination of the NRC license. Once the NRC determines that the decommissioning is completed, the license is terminated. At that point, the NRC no longer has regulatory authority over the site, and the owner of the site is no longer subject to NRC regulations. As a result, activities performed after license termination and the resulting impacts are outside the scope of this Supplement. These activities may include any non-NRC required monitoring, site restoration (grading, planting of vegetation, etc.), continued dismantlement or continued use of the site for activities such as power production using natural gas, oil, or coal.

Any potential radiological impacts following license termination that are related to activities performed during decommissioning are not considered in this Supplement. Such impacts are covered by the Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities, NUREG-1496 (NRC 1997).

Any potential nonradiological impacts resulting from decommissioning and occurring after termination of the license are considered within the scope of this Supplement. Onsite disposal has been proposed by the industry as a method to dispose of slightly radiologically contaminated building rubble provided that the waste is buried onsite below grade, for example, in existing underground portions of the dismantled plant in such a manner as to meet the site release criteria of 10 CFR Part 20, Subpart E. This concept has been referred to as "Rubblization" (the disposal onsite of slightly contaminated material in a manner to meet the 10 CFR Part 20 release criteria).[a] On February 14, 2000, the staff informed the Commission of licensee interest in this method and the staff's intent to address Rubblization in this Supplement (NRC 2000). The staff has determined that the long-term radiological aspects of Rubblization, or onsite disposal of slightly contaminated material, would require a site-specific analysis and would be addressed at the time the LTP is submitted. The nonradiological impacts, occurring both during the decommissioning period (e.g., noise, dust, land disturbance), and the long-term impacts occurring after the decommissioning activities are completed (e.g., concrete leaching into the groundwater) can be evaluated generically and are included in the evaluation of each of the applicable environmental issues in Chapter 4 of this document.

Public perceptions and psychological impacts related to the risk of a radiological accident during decommissioning are not addressed in the 1988 GEIS and are not addressed in this Supplement. The U.S. Supreme Court stated in *Metropolitan Edison Co. v. People Against Nuclear Energy*, 460 U.S. 766, at 774-775, that such psychological effects or impacts raised policy questions that fell outside of NEPA. This court case involved an organization of residents living in the area of Three Mile Island, People Against Nuclear Energy (PANE), that claimed the NRC should consider, as part of an EIS, the severe psychological stress caused to its members by the restart of Three Mile Island, Unit 1, after the accident at Three Mile Island, Unit 2. However, in *Metropolitan Edison Co., et al. v. People Against Nuclear Energy* (1983), the Supreme Court read NEPA to require

> a reasonably close causal relationship between a change in the physical environment and the effect at issue .... a risk of an accident is not an effect on the physical environment .... We believe that the element of risk lengthens the causal chain beyond the reach of NEPA.

(a) The term "rubblization" is frequently used to describe the crushing of structural material (e.g., concrete) to facilitate disposal. The material may be concrete that is uncontaminated or contaminated with radiological material. The staff used the term Rubblization to describe the process of onsite disposal of slightly contaminated material in a manner to meet the site release criteria. For this report, in order to avoid confusion, the staff chose to use the term "demolition" instead of rubblization as the verb to describe the process of crushing structural material to allow for easy burial or disposal.

The decommissioning activities following shutdown of a facility after a major accident resulting in significant contamination of the site are outside the scope of this Supplement. For most types of accidents, decommissioning would be treated on a site-specific basis and, therefore, cannot be considered in a generic sense.

1.4 Categories for Environmental Impacts and Extent of Issues

In the analysis of potential issues in decommissioning activities, two areas in particular were found to benefit from categorization: (a) ranking the significance and severity of potential environmental impacts for proposed decommissioning activities and (b) sorting potential issues as either generic or site-specific.

1.4.1 Levels of Significance of Environmental Impacts

For decommissioning, the staff is using a standard of significance derived from the CEQ terminology for "significantly" (40 CFR 1508.27, which considers "context" and "intensity"). The NRC has defined three significance levels: SMALL, MODERATE, and LARGE.

SMALL – Environmental impacts are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts in this Supplement, the NRC has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

MODERATE – Environmental impacts are sufficient to alter noticeably, but not to destabilize, important attributes of the resource.

LARGE – Environmental impacts are clearly noticeable and are sufficient to destabilize important attributes of the resource.

The discussion of each environmental issue in this Supplement includes an explanation of how the significance level was determined. In determining the significance level, the NRC staff assumed that ongoing mitigation measures would continue (including those mitigation measures implemented during plant construction and/or operation) during decommissioning, as appropriate. Benefits of additional mitigation measures during or after decommissioning are not considered in determining significance levels.

1.4.2 Regulatory Distinction of Generic and Site-Specific Approaches

In addition to determining the significance of environmental impacts, this Supplement includes a determination of whether the analysis of the environmental issue could be applied to all plants, and whether additional mitigation measures would be warranted. An environmental issue may be assigned to one of two categories (generic or site-specific) described below.

- Generic – For each environmental issue, the analysis reported in this Supplement shows the following:

  (1) Environmental impacts associated with the issue have been determined to apply either to all plants, or for some issues to plants having a specific size, specific location, or having a specific type of cooling system or other site characteristics, and

  (2) A single significance level (i.e., SMALL, MODERATE, or LARGE) has been assigned to the impacts, and

  (3) Mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are not likely to be sufficiently beneficial to warrant implementation.

- Site-specific – For each environmental issue that was determined to be site-specific, the analysis reported in this Supplement has shown that one or more of the generic criteria was not met. Therefore, additional plant-specific review is required.

1.5 Uses of This Supplement

This Supplement can be used by the public to understand the decommissioning process, the activities performed during decommissioning, and the potential environmental impacts resulting from these activities. The Supplement does not (1) establish or revise regulations, (2) impose requirements, (3) provide relief from requirements, or (4) provide guidance on the decommissioning process.

This Supplement identifies activities that can be bounded by a generic evaluation. It also identifies the decommissioning activities and associated environmental issues that will likely require site-specific analysis before performing a decommissioning activity.

Licensees can rely on the information in this Supplement as a basis for meeting the requirements in 10 CFR 50.82(a)(6)(ii). This requirement states that the licensee must not perform any decommissioning activity that causes any significant environmental impact not previously

reviewed. Prior to conducting a decommissioning activity, the licensee must make a determination that the resulting environmental impacts fall within the bounds of this Supplement or of another EIS related to its facility. When finalized, licensees are expected to reflect the environmental impacts described in this Supplement rather than those in the 1988 GEIS. For any decommissioning activity that does not meet these conditions, the regulations prohibit the licensee from undertaking the activity until it performs a site-specific analysis of the activity. Depending on the results of the site-specific evaluation, the staff may determine that it is appropriate to consult with another agency about the potential impacts. Such agencies could include the U.S. Fish and Wildlife Service or a State Historic Preservation Office. If the activity would result in an impact that is outside the bounds of the GEIS or other environmental assessments, the licensee would be required to submit a license-amendment request. The NRC staff periodically inspects the licensee's procedures and documentation to ensure that a proper environmental review is part of the screening criteria used for proposed changes to the facility.

In addition to the NRC staff's review of the licensee's procedures and documentation, there are two points during the decommissioning process when the licensee performs an evaluation of environmental impacts. The first evaluation occurs when the licensee must submit a PSDAR to the NRC (within two years following permanent cessation of operation). The PSDAR must include a discussion that provides the reasons for concluding that the environmental impacts associated with the licensee's planned site-specific decommissioning activities will be bounded by an appropriate previously issued environmental assessments, including this Supplement. If the licensee identifies environmental impacts that are not bounded by a previous NRC environmental assessment, the licensee must address the impacts in a request for a license amendment regarding the activities. The licensee must also submit a supplement to its environmental report (ER) that describes and evaluates the additional impacts. The NRC will review the supplement to the ER in conjunction with its review of the license-amendment request.

The second evaluation is near the end of decommissioning at the time when the licensee submits an application for license termination. In accordance with 10 CFR 50.82(a)(9), a licensee must submit its LTP at least 2 years before the anticipated termination date of the license. The LTP must be a supplement to the Final Safety Analysis Report or its equivalent for the facility and is submitted as a license amendment. The NRC requires an environmental review as part of the review of the license-amendment request. Thus, the LTP must include a supplement to the ER that describes any new information or significant environmental change associated with the licensee's proposed termination activities. The NRC staff will also rely upon this supplement as a basis for determining if anticipated decommissioning impacts require an additional review.

1.6 Development of This Supplement

The requirements in 10 CFR Part 51 were followed for the development of this Supplement. This included conducting scoping meetings and obtaining public comments (see Appendix N). From these meetings and meetings with other appropriate government agencies, the staff defined the scope of this Supplement (see Sections 1.2 and 1.3). During the scoping process, the staff developed an evaluation process for determining the environmental impacts from decommissioning. Section 4.2 provides additional discussion of the process and Appendix E provides a detailed description of the analysis used to identify the environmental impacts from decommissioning. The evaluation process involved determining the specific activities that occur during decommissioning and obtaining data from site visits and from an information request to decommissioning plants that was related to the impact of these activities at currently decommissioning facilities. The data obtained from the decommissioning sites were analyzed and then evaluated against a list of variables that defined the parameters for plants that are currently operating but which will one day be decommissioned. This evaluation resulted in a range of impacts for each environmental issue that may be used for comparison by licensees that are or will be decommissioning their facilities.

1.7 Parts of This Supplement

Chapter 2 provides background, describing the basis for the current regulations and summarizing the regulations. Chapter 3 describes the types of plants covered by this Supplement, which includes permanently shutdown reactor facilities as well as operating facilities that will eventually cease power operations. Chapter 3 also describes the location and types of buildings on the sites, the systems that may still be active after permanent shutdown, and changes in effluents after permanent shutdown. Chapter 4 describes activities conducted during the decommissioning process and impacts that could arise from these activities. The analysis of the impacts is based on variables such as the option of decommissioning, location of plant, type of plant, and timing of the activity. Chapter 5 discusses the "No Action" alternative to decommissioning, which is the abandonment of the facility after the cessation of operations. Chapter 6 contains the summary of findings and conclusions.

1.8 References

10 CFR 20. Code of Federal Regulations, Title 10, *Energy*, Part 20, "Standards for protection against radiation."

10 CFR 50. Code of Federal Regulations, Title 10, *Energy*, Part 50, "Domestic licensing of production and utilization facilities."

10 CFR 51. Code of Federal Regulations, Title 10, *Energy*, Part 51, "Environmental protection regulations for domestic licensing and related regulatory functions."

10 CFR 60. Code of Federal Regulations, Title 10, *Energy*, Part 60, "Disposal of high-level radioactive wastes in geologic repositories."

10 CFR 61. Code of Federal Regulations, Title 10, *Energy*, Part 61, "Licensing requirements for land disposal of radioactive waste.

10 CFR 63. Code of Federal Regulations, Title 10, *Energy*, Part 63, "Disposal of high-level radioactive wastes in a geologic repository at Yucca Mountain, Nevada."

10 CFR 71. Code of Federal Regulations, Title 10, *Energy*, Part 71, "Packaging and transportation of radioactive material."

10 CFR 72. Code of Federal Regulations, Title 10, *Energy*, Part 72, "Licensing requirements for the independent storage of spent nuclear fuel, high-level radioactive waste, and reactor-related greater-than-Class-C waste."

40 CFR 1508. Code of Federal Regulations, Title 40, *Protection of the Environment*, Part 1508, "Terminology and Index."

54 FR 39767. "10 CFR Part 51 Waste Confidence Decision Review." *Federal Register*. September 28, 1989.

64 FR 68005. "Waste Confidence Decision Review." *Federal Register*. December 6, 1999.

66 FR 55732. "Disposal of High-Level Radioactive Wastes in a Proposed Geologic Repository at Yucca Mountain, Nevada." *Federal Register*. November 2, 2001.

Metropolitan Edison Co., et al v. People Against Nuclear Energy, 460 U.S. 766, at 774-775. 1983.

National Environmental Policy Act (NEPA) of 1969, as amended, 42 USC 4321 et seq.

Nuclear Waste Policy Act of 1982, as amended, 42 USC 10.101 et seq.

U.S. Nuclear Regulatory Commission (NRC). 1982. *Final Generic Environmental Impact Statement for 10 CFR Part 61*. NUREG-0945, NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1988. *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities.* NUREG-0586, NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1997. *Final Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities.* NUREG-1496, Vol. 1, NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 2000. "SECY-00-0041 Use of Rubblized Concrete Dismantlement to Address 10 CFR Part 20, Subpart E, Radiological Criteria for License Termination." NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 2001. Letter from U.S. NRC to Distribution: "Subject: Issuance of a scoping summary report of comments received related to the intent to develop a Supplement to NUREG-0586." Dated April 17, 2001.

2.0 Background Information Related to Decommissioning Regulations

This section provides background information that will assist the reader in understanding the requirements for decommissioning and license termination. The basis for the current decommissioning regulations and a summary of the current regulations are provided below. This chapter and Chapter 3, "Description of NRC Licensed Reactor Facilities and the Decommissioning Process," will give the reader a basic understanding of the overall reactor decommissioning process and environmental impact assessments used during the process.

2.1 Basis for Current Regulations

In the mid-1990s, the Commission initiated an effort to significantly change the regulations for decommissioning power reactor facilities. The new regulations were intended to make the decommissioning process more current, efficient, and uniform. On July 29, 1996, a final rule revising 10 CFR 50.82, "Decommissioning of Nuclear Power Reactors," was published in the Federal Register (61 FR 39278). This rule redefined the decommissioning process and modified the regulations written in 1988, which had required submittal of a detailed decommissioning plan before the start of decommissioning.

The regulations were revised based on experience gained from reactor decommissionings that had occurred during the 1980s and early 1990s. Review of the activities that occur during decommissioning showed that they are similar to the activities that occur during the construction, operation, maintenance, and refueling outages of a power reactor (e.g., decontamination, steam generator replacement, and pipe removal). However, the magnitude of some activities during decommissioning (e.g., removal of piping) is considerably greater than during operations. Activities associated with the decommissioning of facilities had resulted in impacts consistent with or less than those evaluated in the 1988 *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* (GEIS), NUREG-0586 (NRC 1988). Based on the above reasons, the Commission determined that review and approval by the U.S. Nuclear Regulatory Commission (NRC) staff of a detailed decommissioning plan was not necessary.

2.2 Summary of Current Regulations

2.2.1 Regulations for Decommissioning Activities

The current regulations (10 CFR 50.82) specify the regulatory actions that both the NRC and the licensee must take to decommission a nuclear power facility. Once the licensee decides to permanently cease operations, it must submit, within 30 days, a written certification to the NRC.

The notification must contain the date on which the power-generating operations ceased or will cease. The licensee must permanently remove all fuel from the reactor and submit a written certification to the NRC confirming the completion of fuel removal. Once this certification has been submitted, the licensee is no longer permitted to operate the reactor, or to put fuel back into the reactor vessel. After certification that the fuel is removed, the annual license fee to the NRC is reduced as well as the licensee's obligation to adhere to certain requirements that are needed only during reactor operations.

In addition to the certifications, the licensee must submit a post-shutdown decommissioning activities report (PSDAR) to the NRC and any affected States no later than 2 years after the date of permanent cessation of operations. Section 10 CFR 50.82 requires that the PSDAR include

- a description of the licensee's planned major decommissioning activities
- a schedule for completing these activities
- an estimate of the expected decommissioning costs
- a discussion that provides the reasons for concluding that the environmental impacts associated with site-specific decommissioning activities will be bounded by an appropriate previously issued environmental impact statement (EIS).

After receiving a PSDAR, the NRC publishes a notice of receipt in the Federal Register, makes the PSDAR available for public review and comment, and holds a public meeting in the vicinity of the facility to discuss the licensee's plans. The NRC will examine the PSDAR to determine if the required information is included and will inform the licensee in writing if there are deficiencies that must be addressed before the licensee initiates any major decommissioning activities. The regulations require a 90-day waiting period after submittal of the PSDAR before the licensee may commence major decommissioning activities.

The purpose of the PSDAR is to provide the NRC and the public with a general overview of the licensee's proposed decommissioning activities. The PSDAR serves to inform the NRC staff of the licensee's expected activities and schedule, which facilitates planning for inspections and decisions regarding NRC oversight activities. The PSDAR is also a mechanism for informing the public of the proposed decommissioning activities before those activities are conducted.

Prior to submission of the PSDAR, the licensee can conduct a variety of activities at the site including activities to ensure the safe shutdown of the facility. Systems can be drained, components removed, and certain structures demolished. However, the licensee is prohibited from undertaking any major decommissioning activity as defined in 10 CFR 50.2.

Once the PSDAR has been submitted and the 90-day period has been completed, the licensee may begin major decommissioning activities, which may include the following:

- permanent removal of major radioactive components, such as the reactor vessel, steam generators, or other components that are comparably radioactive
- permanent changes to the containment structure
- dismantling of components containing Greater-than-Class-C (GTCC) Waste.[a]

In accordance with 10 CFR 50.82(a)(6)(ii), licensees shall not perform any decommissioning activities "that result in significant environmental impacts not previously reviewed." If any decommissioning activity does not meet this requirement, the licensee must submit a license-amendment request before conducting the activity. The licensee also must submit a supplement to its environmental report (ER) that relates to the additional impacts. The NRC will review the ER Supplement, and prepare an environmental assessment (EA) or EIS, and amendment to the license in conjunction with its review.

The licensee can choose (1) to immediately decontaminate and dismantle the facility (DECON), or (2) to place the facility in long-term storage (SAFSTOR) followed by subsequent decontamination and dismantlement, or (3) to perform some incremental decontamination and dismantlement activities before or during the storage period of SAFSTOR. Under the current regulations, unless the licensee receives permission to the contrary, the site must be decommissioned within 60 years. Chapter 3 describes in more detail the decommissioning

(a) The NRC has adopted a waste classification system for low-level radioactive waste based on its potential hazards, and has specified disposal and waste form requirements for each of the general classes of waste: A, B, and C. The classifications are based on the key radionuclides present in the waste and their half-lives. Tables defining these three classes are contained in 10 CFR 61.55. In general, requirements for waste form, stability, and disposal methods become more stringent when going from Class A to Class C. GTCC waste exceeds the concentration limits in 10 CFR 61.55 and is generally unsuitable for near-surface disposal as low-level waste (LLW), even though it is legally defined as LLW. The NRC's regulations in 10 CFR 61.55(a)(2)(iv) require that this type of waste must be disposed of in a geologic repository unless approved for an alternative disposal method on a case-specific basis by the NRC. 10 CFR Part 72 allows for interim storage of GTCC from a commercial power reactor.

options available to the licensee. In this Supplement, the staff also evaluates another option called ENTOMB, which encases the radioactive contaminants in a structurally long-lived material.

2.2.2 Regulations for License Termination

In order to terminate the license and allow release of the site, the licensee must submit a license termination plan (LTP). In accordance with 10 CFR 50.82(a)(9), an application for license termination must be accompanied or preceded by an LTP, which is subject to NRC review and approval. The licensee must submit the LTP at least 2 years before the date of license termination. The LTP approval process is by license amendment. By regulation, the LTP must include the following:

- a site characterization
- identification of remaining dismantlement activities
- plans for site remediation
- detailed plans for the final survey of residual contamination
- a description of the end-use of the site (if restricted use is proposed)
- an updated site-specific estimate of remaining decommissioning costs
- a supplement to the ER.

The licensee must submit the LTP as a supplement to its Final Safety Analysis Report or as an equivalent document, thus formalizing the steps necessary to revise the document.

After receiving the LTP, the NRC will place a notice of receipt of the plan in the Federal Register and will make the plan available to the public for comment. The NRC will schedule a public meeting near the facility to discuss the plan's contents and the staff's process for reviewing the submittal. The NRC will also offer an opportunity for a public hearing on the license-amendment request associated with the LTP. At this stage, a site-specific EA is required. Depending on the circumstances, the EA evaluation can result in the development of a full EIS. If the LTP demonstrates that the remainder of decommissioning activities will be performed in accordance with NRC regulations, are not detrimental to the health and safety of the public, and will not have a significant adverse effect on the quality of the environment, the

Commission will approve the plan by a license amendment (subject to whatever conditions and limitations the Commission deems appropriate and necessary).

After the approval of the LTP, the NRC will continue its inspection of the site. These inspections will include validation of commitments made in the LTP. Inspections may also include confirmatory surveys to verify that areas of the site have been decontaminated to the limits established in the LTP.

On July 21, 1997, the NRC published (also in the Federal Register) a final rule entitled, "Radiological Criteria for License Termination" (64 FR 39058) prescribing specific radiological criteria for license termination. At the end of the LTP process, if the NRC determines that the remaining dismantlement has been performed in accordance with the approved LTP, and if the final radiation survey and associated documentation demonstrate that the facility and site are suitable for release, then the Commission will terminate the license.

The radiological criteria for license termination are given in 10 CFR Part 20, Subpart E. There are two broad categories of uses for the facility after the license termination: unrestricted use and restricted use.

Unrestricted use means that there are no NRC-imposed restrictions on how the site may be used. State and local jurisdictions may, and have, imposed additional restrictions or requirements on licensees. The licensee is free to continue to dismantle any remaining buildings or structures and to use or sell the land for any type of application. The Commission has established a 0.25 mSv/yr (25 mrem/yr) total effective dose equivalent (TEDE) to an average member of the critical group[a] as an acceptable criterion for release of any site for unrestricted

(a) The "critical group" is that group of individuals reasonably expected to receive the highest exposure to residual radioactivity within the assumptions of a particular scenario. The average dose to a member of the critical group is represented by the average of the doses for all members of the critical group, which in turn is assumed to represent the most likely exposure situation. For example, when considering whether it is appropriate to "release" a building that has been decontaminated (allow people to work in the building without restrictions), the critical group would be the group of employees that would regularly work in the building. If radiation in the soil is the concern, then the scenario used to represent the maximally exposed individual is that of a resident farmer. The assumptions used for this scenario are prudently conservative and tend to overestimate the potential doses. The added "sensitivity" of certain members of the population, such as pregnant women, infants, children, and any others who may be at higher risk from radiation exposures, are accounted for in the analysis. However, the most sensitive member may not always be the member of the population that receives the highest dose. This is especially true if the most sensitive member (e.g., an infant) does not participate in activities that provide the greatest dose or if they do not eat specific foods that cause the greatest dose.

use. The licensee will be required to show that the site can meet this criterion before the license will be terminated for unrestricted use. In addition, the licensee will need to show that the amounts of residual radioactivity have been reduced to levels that are as low as reasonably achievable (ALARA).[a] For sites that have been determined to be acceptable for unrestricted use, there are no requirements for further measurement of radiation levels. It is not expected that these radiation levels would change (other than to be reduced over time through radioactive decay), and there would be no mechanism for further contamination or radiological releases.

Restricted use means that there are restrictions on the facility use after license termination. A site would be considered acceptable for license termination under restricted conditions if the licensee can demonstrate that further reductions in residual radioactivity necessary to meet the requirements for unrestricted use would result in net public or environmental harm, or were not being made because the residual levels were ALARA. In addition, the licensee must have made provisions for legally enforceable institutional controls (e.g., use restrictions placed in the deed for the property) that provide reasonable assurance that the radiological criteria set by the NRC (0.25 mSv/yr [25 mrem/yr] TEDE to an average member of the critical group) will not be exceeded. The licensee must also have provided sufficient financial assurance to an amenable independent third party to assume and carry out responsibilities for any necessary control and maintenance of the site. There are also regulations relating to the documentation of how the advice of individuals and institutions in the community who may be affected by decommissioning has been sought and incorporated in the LTP if the license is to be terminated under restricted conditions.

Residual radioactivity at the site must be reduced so that if the institutional controls were no longer in effect, there would be reasonable assurance that the TEDE from residual radioactivity distinguishable from background to the average member of the critical group would be ALARA and would not exceed either 1 mSv/yr (100 mrem/yr) or 5 mSv/yr (500 mrem/yr). In the latter case, the licensee must (1) demonstrate that further reductions in residual radioactivity necessary to comply with the 1 mSv/yr (100 mrem/yr) value are not technically achievable, would be prohibitively expensive, or would result in net public or environmental harm, (2) make provisions for durable institutional controls, and (3) provide sufficient financial assurance to enable a responsible government entity or independent third party to carry out periodic checks of the facility no less frequently than every 5 years to ensure that the institutional controls remain in place.

(a) The ALARA concept means that all doses are to be reduced below required levels to the lowest reasonably achievable level considering economic and societal factors. Determination of levels that are ALARA must consider any detriments, such as deaths from transportation accidents, that are expected to potentially result from disposal of radioactive waste.

Alternate release criteria may be used in specific cases. The use of alternate criteria to terminate a license requires the approval of the Commission after consideration of the NRC staff's recommendations that address comments provided by the U.S. Environmental Protection Agency and any public comments submitted pursuant to 10 CFR 20.1405. These alternate criteria are expected to be used only in very rare cases.

To date, the three NRC-licensed facilities (Shoreham, Fort St. Vrain, and Pathfinder) that have completed the decommissioning process have had their licenses terminated, allowing unrestricted use of the sites. License termination plans have been submitted for three other facilities. The LTPs describe plans for unrestricted use of the sites following license termination. No nuclear power licensees have indicated that they plan for restricted use of the site after license termination.

A proposed rule was issued on September 4, 2001 (66 FR 46230) for partial site release prior to license termination. Partial site release means release of part of a nuclear power reactor facility or site for unrestricted use prior to NRC approval of the LTP. The NRC proposes to add a new section to 10 CFR Part 50, separate from the existing rules for decommissioning and radiological criteria for license termination, that identifies the requirements and criteria necessary for partial site release. The proposed rule includes associated amendments to 10 CFR Part 2 and 10 CFR Part 20. The purpose of this rulemaking is to ensure that any remaining residual radioactive material from licensed activities on a portion the site released for unrestricted use will meet the radiological criteria for license termination.

Licensees will be required to submit information necessary to demonstrate the following:

- The release of radiologically impacted property complies with the radiological criteria for unrestricted use in 10 CFR 20.1402 (0.25 mSv/yr [25 mrem/yr] to the average member of the critical group and ALARA).

- The licensee will continue to comply with all other applicable regulatory requirements that may be affected by the release of property and changes to the site boundary. This would include, for example, requirements in 10 CFR Parts 20, 50, 72, and 100.

- Records of property-line changes and the radiological conditions of partial site releases are being maintained to ensure that the dose from residual material associated with these releases can be accounted for at the time of any subsequent partial releases and at the time of license termination.

The proposed rule provides additional flexibility to licensees who are releasing property that has never been radiologically impacted. While an amendment of the Part 50 operating license is required to release radiologically impacted property, the proposed rule offers the opportunity for a letter submittal for partial releases if the licensee can demonstrate that there is no reasonable potential for residual radioactivity from license activities.

2.3 References

10 CFR 2. Code of Federal Regulations, Title 10, *Energy*, Part 2, "Rules of practice for domestic licensing proceedings and issuance of orders."

10 CFR 20. Code of Federal Regulations, Title 10, *Energy*, Part 20, "Standards for protection against radiation."

10 CFR 50. Code of Federal Regulations, Title 10, *Energy*, Part 50, "Domestic licensing of production and utilization facilities."

10 CFR 61. Code of Federal Regulations, Title 10, *Energy*, Part 61, "Licensing requirements for land disposal of radioactive waste."

10 CFR 72. Code of Federal Regulations, Title 10, *Energy*, Part 72, "Licensing requirements for the independent storage of spent nuclear fuel high-level radioactive waste and reactor-related greater-than-Class-C waste."

10 CFR 100. Code of Federal Regulations, Title 10, *Energy*, Part 100, "Reactor site criteria."

61 FR 39278. "Decommissioning of Nuclear Power Reactors. Final Rule." *Federal Register*. July 29, 1996.

64 FR 39058. "Radiological Criteria for License Termination. Final Rule." *Federal Register*. July 21, 1997.

66 FR 46230. "Releasing Part of a Power Reactor Site or Facility for Unrestricted Use Before the NRC Approves the License Termination Plan. Proposed Rule." *Federal Register*. September 4, 2001.

U.S. Nuclear Regulatory Commission (NRC). 1988. *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities*. NUREG-0586, NRC, Washington, D.C.

3.0 Description of NRC Licensed Reactor Facilities and the Decommissioning Process

This chapter provides information on both the operating nuclear power plants and those being decommissioned. First, a general description of the nuclear power plants and sites is provided in Section 3.1 to help the reader understand the types of reactor facilities that will be decommissioned, the location of the radioactive material in these facilities, and the structures, systems, and components (SSCs) that will be referred to later in this document and that are important in the decommissioning process. Next, the methods that are commonly used during decommissioning are described in Section 3.2. Section 3.3 addresses the decommissioning experience of the currently decommissioning plant sites, their chosen method for decommissioning, and the activities that are being used to decommission the facilities.

There are currently 22 nuclear power reactors at 21 sites that are permanently shut down: 19 of these reactors are in various stages of decommissioning, and reactors at 3 sites have finished decommissioning and no longer maintain a license. The decommissioning efforts at these 22 plants equates to over 200 equivalent years of experience decommissioning commercial power reactors since the 1988 *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities*, NUREG-0586 (1988 GEIS; NRC 1988) was published. There are also currently 104 nuclear plants that have a license and are either operating or have not yet certified that they have permanently ceased power operations. Between 2006 and 2035, these 104 plants will either permanently cease operations or renew their licenses. Ultimately, they will all permanently cease operations and be decommissioned.

3.1 Plants, Sites, and Reactor Systems[a]

Between 1957 and 1996, the U.S. Nuclear Regulatory Commission (NRC) issued 126 operating licenses for commercial power reactor operation at 80 sites. The history of and experience with the 22 reactors that are being decommissioned currently or have completed decommissioning are addressed in Section 3.3. Because each of the remaining 104 operating plants will eventually enter the decommissioning process, their attributes and characteristics are included in this section to ensure that this Supplement is appropriate for future decommissioning plants. The material presented in this section is also provided as background information for the reader.

(a) Much of the information in this section was taken from NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (NRC 1996) and from NUREG-1628, *Staff Responses to Frequently Asked Questions Concerning Decommissioning of Nuclear Power Reactors* (NRC 2000a). This information has been supplemented and updated as appropriate to include all operating and currently decommissioning nuclear plants.

Nuclear power reactor facilities are located in 35 of the contiguous States, with none in Alaska or Hawaii. Thirty-nine sites contain two or three nuclear power reactors (units) per site. Of the 126 plants, 98 are located east of the Mississippi River with most of the nuclear capacity located in the northeast (New England States, New York, and Pennsylvania), the midwest (Illinois, Michigan, and Wisconsin) and the southeast (Virginia, North and South Carolina, Georgia, Florida, and Alabama).

Typically, nuclear power plants are sited in flat or rolling countryside, in wooded or agricultural areas away from urban areas. Most are located on or near rivers or lakes. Several plants are located in arid regions, and 19 plants are located along the seacoast on bays or inlets. More than 50 percent of the sites have 80-km (50-mile) population densities of less than 77 persons/km^2 (200 persons/mi^2) and over 80 percent have 80-km (50-mile) densities of less than 193 persons/km^2 (500 persons/mi^2). The most notable exception is the Indian Point Station, located within 80 km (50 mi) of New York City, which has a projected 1999 population density within 80 km (50 mi) of more than 770 persons/km^2 (2000 persons/mi^2). Indian Point has one permanently shutdown reactor and two operating reactors.

Site areas range from a minimum of 34 ha (84 ac) for the San Onofre Nuclear Generating Station, (a three unit site, with one permanently shutdown reactor) in California to 9700 ha (24,000 ac) for the Turkey Point Plant in Florida (two operating units). Almost 60 percent of plant sites cover from 200 to 800 ha (500 to 2000 ac). Larger land-use areas are associated with plant cooling systems that include reservoirs, artificial lakes, and buffer areas.

Appendix F contains summary tables for both permanently shutdown and currently operating nuclear power facilities showing location, reactor type, thermal power, site area, cooling system and cooling water source, and licensing dates.

3.1.1 Types of Nuclear Power Reactor Facilities

In the United States, nearly all reactors used for commercial power generation have been conventional (thermal) light water reactors (LWRs) that use water as a moderator and coolant. The two types of LWRs are pressurized water reactors (PWRs) and boiling water reactors (BWRs). Of the 123 LWRs, 80 are PWRs and 43 are BWRs. The three plants that are not LWRs are Fermi, Unit 1, which is a permanently shutdown fast breeder reactor (FBR), and Peach Bottom, Unit 1, and Fort St. Vrain, which are permanently shutdown high-temperature gas-cooled reactors (HTGRs). Fermi, Unit 1, is currently performing the decontamination and

dismantlement phase of SAFSTOR (see Section 3.2). Peach Bottom, Unit 1, is in long-term storage. Fort St. Vrain has had its license terminated following completion of decommissioning activities.

Brief descriptions of these different types of reactors are given below as background.

3.1.1.1 Pressurized Water Reactors

In PWRs, water is heated to a high temperature under pressure inside the reactor. The water is then pumped in the primary circulation loop to the steam generator. Within the steam generator, water in the secondary circulation loop is converted to steam that drives the turbines. The turbines turn the generator to produce electricity. The steam leaving the turbines is condensed by water in the tertiary loop and returned to the steam generator. The tertiary loop water flows either to cooling towers, where it is cooled by evaporation or discharged to a body of water such as a river, lake, or other heat sink. The tertiary loop is open to the atmosphere, but the primary and secondary cooling loops are not (see Figure 3-1).

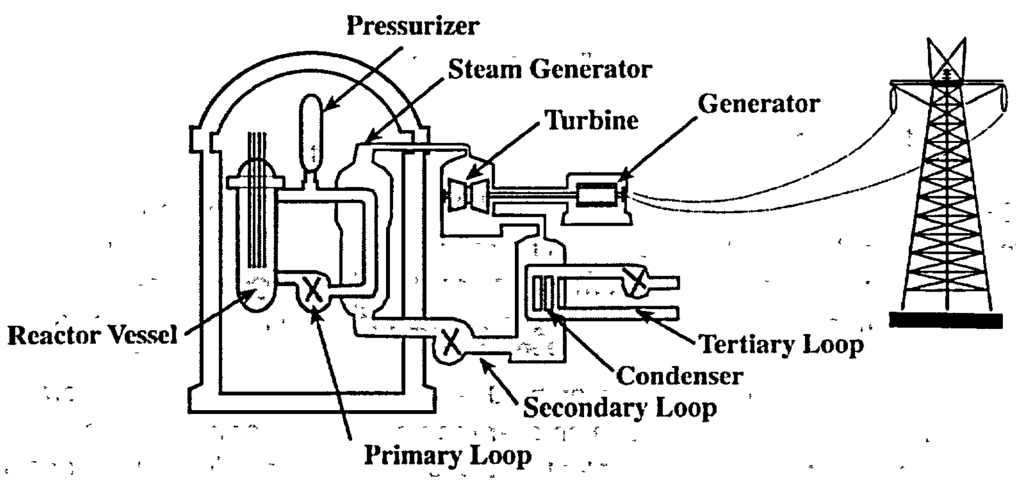


Figure 3-1. Pressurized Water Reactor

3.1.1.2 Boiling Water Reactors

The BWRs generate steam directly within the reactor vessel. The steam passes through moisture separators and steam dryers and then flows to the turbine. By generating steam directly in the reactor vessel, the power generation system contains only two heat transfer loops. The primary loop transports the steam from the reactor vessel directly to the turbine, which generates electricity. The secondary coolant loop removes excess heat from the primary

loop in the condenser. From the condenser the primary condensate proceeds into the feedwater stage and the secondary coolant loop removes the excess heat to the environment (see Figure 3-2).

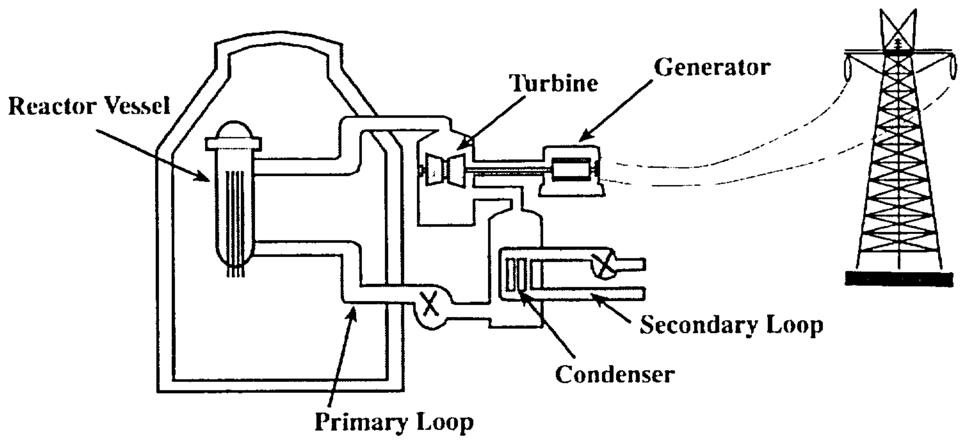


Figure 3-2. Boiling Water Reactor

3.1.1.3 Fast Breeder Reactors

In the FBR, such as Fermi, Unit 1, liquid sodium is used as the reactor coolant instead of water. The Fermi, Unit 1, FBR used the fissile isotope of uranium as fuel. During the chain reaction, while some neutrons are fissioning plutonium atoms and releasing heat energy, others are captured by uranium atoms, which are then converted into more plutonium atoms. Depending on design, a fast breeder can produce 1.4 new plutonium atoms for every one fissioned–enough to refuel another reactor in 10 years. Fast breeders also generally have a higher power density in the core (thus, a smaller reactor) and better heat transfer characteristics, which improves power-plant efficiency. The Fermi, Unit 1, reactor also utilized a steam cycle to generate electricity, similar to a PWR. However, the Fermi, Unit 1, reactor had two sodium loops. Primary-loop liquid sodium was circulated through the reactor core, where it absorbed the heat generated by the reactor, and then through a heat exchanger, where its heat was transferred to the second (intermediate) sodium loop. The intermediate-loop liquid sodium was then circulated through a steam generator. The steam produced in the steam generators was then circulated to the turbine generators to produce electricity.

At this time, there are no commercial FBRs operating or under construction in the United States. Fermi, Unit 1, is currently in SAFSTOR. The environmental impacts described in this Supplement for FBRs are applicable to Fermi, Unit 1.

3.1.1.4 High-Temperature Gas-Cooled Reactors

Commercial HTGRs, operated in the United States at Peach Bottom, Unit 1, and Fort St. Vrain, use helium gas instead of water (as in LWRs) to transfer the heat from the reactor core to produce steam. In HTGRs, the entire primary coolant system, including the reactor, the steam generators, and the helium circulators, is housed within a prestressed concrete or steel reactor vessel. The helium circulators pump the pressurized coolant through the core, where it absorbs the heat from the fission process. The helium then enters the steam generators, which transfer the heat to the secondary system. The secondary system is a steam cycle similar to that found in any modern fossil-fuel facility. Superheated steam is produced in the steam generators and routed to the turbine generator, which generates the electricity (Fuller 1988).

At this time, there are no HTGRs operating or under construction in the United States. Decommissioning at Fort St. Vrain is complete and the license is terminated, and Peach Bottom, Unit 1, is currently in SAFSTOR. The environmental impacts described in this Supplement for HTGRs are applicable to Peach Bottom, Unit 1.

3.1.2 Types of Structures Located at a Nuclear Power Facility

As discussed in Chapter 1, the definition of decommissioning includes the reduction of residual radioactivity to a level that permits release of the property and termination of the license. As a result, the decontamination and/or dismantlement of those SSCs that are radioactive are, by definition, included within the scope of this Supplement as part of decommissioning. If the structures must be decontaminated or parts of the structures removed to meet the requirements for the termination of the NRC license, those activities are also considered within scope as part of the decommissioning process. This includes removing nonradiological structures necessary to decontaminate another structure. Additionally, the impacts of dismantling all SSCs that were built or installed at the site to support power production are considered in this Supplement. This section discusses all the structures that will be referred to later in the document as background information for the reader.

Nuclear power plants generally contain similar facilities. They all contain a nuclear steam supply system, as described in Section 3.1.1 above. Additionally, there are a number of common SSCs necessary for plant operation. However, the layout of buildings and structures varies considerably among the sites. For example, control rooms may be located in the auxiliary building, in a separate control building, or in a radwaste and control building. Thus, the following list describes typical structures located on most sites.

- Containment or reactor building: The containment or reactor building in a PWR is a massive concrete or steel structure that houses the reactor vessel, reactor coolant piping and pumps, steam generators, pressurizer, pumps, and associated piping. The reactor building structure of a BWR generally includes a containment structure and a shield building. The containment is a massive concrete or steel structure that houses the reactor vessel, the reactor coolant piping and pumps, and the suppression pool. It is located inside a somewhat less substantive structure called the shield building. The shield building for a BWR also generally contains the spent fuel pool and the new fuel pool.

  The reactor building for both PWRs and BWRs is designed to withstand such disasters as hurricanes and earthquakes. The containment's ability to withstand such disasters and to contain the effects of accidents initiated by system failures are the principal protections against releasing radioactive material to the environment.

  The containment building for the FBR is a steel-domed structure that contains the upper end of the reactor vessel and the fuel-handling equipment. Below ground there is considerable concrete shielding.

  The HTGRs have two containment structures. Peach Bottom's inner containment structure is made of a steel pressure vessel and Fort St. Vrain's was made of prestressed concrete. This inner vessel houses the entire primary coolant system, the interconnecting ducts and plenums, the reactor core assembly, and the steam generator. The inner vessel is housed inside a second containment structure, which is designed to contain the entire primary coolant system helium under conditions postulated for the design basis accident.

- Fuel building: For PWRs, the fuel building has a fuel pool that is used for the storage and servicing of spent fuel and the preparation of new fuel for insertion into the reactor. This building is connected to the reactor building by a transfer tube or channel that is used to move new fuel into the reactor and to move spent fuel out of the reactor for storage.

- Turbine building: The turbine building houses the turbine generators, condenser, feedwater heaters, condensate and feedwater pumps, waste-heat rejection system, pumps, and equipment that supports those systems. Primary coolant is circulated through these systems in BWRs, thereby causing them to become slightly contaminated. Primary coolant is not circulated through the turbine building systems in PWRs. However, it is not unusual for portions of the turbine building to become mildly contaminated during power generation at PWRs.

- Auxiliary buildings: Auxiliary buildings house such support systems as the ventilation system, the emergency core cooling system, the laundry facilities, water treatment system, and waste treatment system. The auxiliary building may also contain the emergency diesel generators and, in some PWRs, the fuel storage facility. Often, the facility's control room is also located in the auxiliary building.

- Diesel generator building: Often, there is a separate building for housing the emergency diesel generators if they are not located in the auxiliary building. The emergency diesel generators do not become contaminated or activated.

- Pumphouses: Various pumphouses may be present onsite for circulating water, standby service water, or makeup water. Pumphouses that carry clean water do not require radiological decommissioning.

- Cooling towers: Cooling towers are structures that are designed to remove excess heat from the condenser without dumping the heat directly into water bodies, such as lakes or rivers. There are two principal types of cooling towers: mechanical draft towers and natural draft towers. Most nuclear plants that have once-through cooling do not have cooling towers associated with them (see the descriptions in Section 3.1.3). However, five facilities with once-through cooling also have cooling towers.

- Radwaste facilities: If the radwaste facilities are not contained in the auxiliary building, they may be located in a separate solid radwaste building. An interim radwaste storage facility may also be used.

- Ventilation stack: Many older nuclear power plants, particularly BWRs, have ventilation stacks to discharge gaseous waste effluents and ventilation air. These stacks can be 90 m (300 ft) tall or more and contain monitoring systems to ensure that radioactive gaseous discharges are below fixed release limits. Radioactive gaseous effluents are treated and processed prior to discharge out the stack.

The following structures may also be part of the nuclear reactor facility but are not evaluated in this Supplement.

- Independent spent fuel storage installations (ISFSI): An ISFSI is designed and constructed for the interim storage of spent nuclear fuel and other radioactive materials associated with spent fuel storage. ISFSIs may be located at the site of a nuclear power plant or at another location. The most common design for an ISFSI, at this time, is a concrete pad with dry casks containing spent fuel bundles. ISFSIs are used by operating plants that require increased spent fuel storage capability because their spent fuel pools have reached

capacity. Decommissioning facilities also use ISFSIs. The first dry-storage installation was licensed by the NRC in 1986. As of August 21, 2002, there were 23 nuclear power facilities licensed to use dry storage: Surry, Oconee, H.B. Robinson, Calvert Cliffs, Fort St. Vrain, Palisades, Point Beach, Prairie Island, Davis-Besse, Susquehanna, Arkansas Nuclear One, North Anna, Trojan, Dresden, Hatch, McGuire, Oyster Creek, Peach Bottom, Yankee Rowe, Fitzpatrick, Rancho Seco, Maine Yankee, and U.S. Department of Energy (DOE [TMI-2 fuel debris]) at Idaho National Engineering and Environmental Laboratory.

An ISFSI can be constructed and operated and decommissioned either under the same license that is used for the operating or decommissioning facility called a general license under 10 CFR Part 50 or a specific license under 10 CFR Part 72 license. If a licensee chose to operate the ISFSI under a Part 50 license, it could, seek a site-specific 10 CFR Part 72 license for the ISFSI, thus allowing termination of the Part 50 license at the end of the decommissioning process. The NRC staff would also be required to conduct an environmental assessment of the licensee's request for a site-specific 10 CFR Part 72 license.

- Switchyard: A plant site also contains a large switchyard, where the electric voltage is stepped up and fed into the regional power distribution system. The switchyard is an integral part of the electric power transmission grid, and may remain on the site even after termination of the license.

- Administrative, training, and security buildings: Normally, the administrative, training, and security buildings are located outside the radiation protection zones, and no radiological hazards are present.

3.1.3 Description of Systems

After permanent cessation of operations and transfer of the fuel from the reactor vessel, licensees begin to shut down systems that are no longer operated in a decommissioning plant. However, specific systems will continue to be used during the different phases of the decommissioning process although in some cases in reduced roles. This section provides background information related to the systems, explains the differences between the systems' use during operations and during the decommissioning process, and explains how their continued operation could impact the environment during the decommissioning process. Lobner et al. (1990) provides more comprehensive descriptions of these systems in U.S. commercial LWRs. The systems described below are typical and may differ at specific facilities.

- Cooling and auxiliary water systems: The predominant water use at an operating nuclear power plant is for removing excess heat generated in the reactor by the condenser cooling system. The quantity of water that is used for condenser cooling in an operating plant is a function of several factors, including the capacity rating of the plant and the increase in cooling water temperature from the discharge to the intake. The cooling water system for the reactor is not operated after the facility has permanently ceased power operations and the fuel has been removed from the reactor vessel. Therefore, water use is greatly reduced when operations cease. However, systems are not immediately drained upon cessation of operation and are frequently left in place for a period of time to provide shielding to the workers.

  There are two major types of cooling systems for operating plants: once-through cooling and closed-cycle cooling.

  In a once-through cooling system, circulating water for condenser cooling is obtained from an adjacent body of water, such as a lake or river, passed through the condenser tubes, and returned at a higher temperature to the adjacent body of water. Flow through the condenser for a 1000-MW plant during operations is typically 45 to 65 m^3/s (700,000 to 1,000,000 gpm) (NRC 1996). The waste heat is dissipated to the atmosphere mainly by evaporation from the water body and, to a much smaller extent, by conduction, convection, and thermal radiation loss.

  In a closed-cycle system at an operating plant, the cooling water is recirculated through the condenser after the waste heat is removed by dissipation to the atmosphere, usually by circulating the water through large cooling towers constructed for that purpose. The average for makeup water withdrawals for a 1000-MW plant during operations is typically about 0.9 to 1.1 m^3/s (14,000 to 18,000 gpm). Recirculating cooling systems consist of either natural draft or mechanical draft cooling towers, cooling ponds, lakes, or canals. Because the predominant cooling mechanism associated with closed-cycle systems is evaporation, most of the water used for cooling is consumed and is not returned to the water source.

  In addition to removing heat from the reactor of an operating facility, cooling water is also provided to the service water system and to the auxiliary water system. These systems account for 1 to 15 percent of the water needed for the condenser cooling. The auxiliary water systems include emergency core cooling systems, the containment spray and cooling system, the emergency feedwater system, the component cooling water system, and the spent fuel pool water systems. Most of these systems would not be needed following permanent cessation of operations. However, some, such as the systems for the spent fuel pool cooling, will be used after the plant has shut down.

- Waste systems (gaseous, liquid, solid, and nonradioactive): The gaseous waste management system in an operating nuclear facility collects fission products, mainly noble gases, that accumulate in the primary coolant. It is designed to reduce the radioactive material in gaseous waste before discharge to meet the dose design objectives in 10 CFR Part 50, Appendix I. During decommissioning, the gaseous waste management system is used during the decontamination and dismantlement of certain tanks or pipes. It is also used during dismantlement to assist in the control of radioactive dust or loose contamination. In addition, high-efficiency particulate air (HEPA) filters are used to remove radioactive material on a localized basis. For example, when removing concrete with a power hammer or drill in the containment building, a temporary plastic tent equipped with a HEPA filter, prevents contaminated dust particles from entering the building. A second set of HEPA filters is located on the exhaust vent pathway for the building. The quantities of gaseous effluents released from operating plants and those in the decommissioning process are controlled by the administrative limits that are defined in the Offsite Dose Calculation Manual (ODCM) or similar document, which is specific for each plant. The limits in the ODCM are designed to provide reasonable assurance that radioactive material discharged in gaseous effluents are not in excess of the limits specified in 10 CFR Part 20, Appendix B, thereby limiting the exposure of a member of the public in an unrestricted area.

  The liquid radioactive waste system in operating nuclear power plants is used to collect and process liquid wastes collected from equipment leaks, valve and pump seal leaks, laundry wastes, personnel and equipment wastes, and steam generator blowdown (for PWRs), as well as building, laboratory, and floor drains. Each of these sources of liquid wastes receives varying degrees and types of treatment before storage, reuse, or discharge to the environment. During decommissioning, any radioactive liquids from operation of decommissioning activities in the facility will be processed and disposed of, thus necessitating the use of the liquid radioactive waste system. Some systems such as the laundry will likely still operate for a period of time, but others like the steam generator blowdown will not. Controls for limiting the release of radiological liquid effluents are described in the facility's ODCM. Controls are based on (1) concentrations of radioactive materials in liquid effluents and projected dose or (2) dose commitments to a member of the public. Concentrations of radioactive material that may be released in liquid effluents to unrestricted areas are limited to the concentration specified in 10 CFR Part 20, Appendix B, Table 2.

  Solid low-level waste (LLW) from nuclear power plants is generated by removal of radionuclides from liquid waste streams, filtration of airborne gaseous emissions, and removal of contaminated material. The major source of solid LLW during decommissioning is the decommissioning process itself. Removal of contamination involves the use of protective clothing and cleaning rags. Dismantlement results in concrete or metal that has

low levels of contamination or activation products. While the amount of liquid and gaseous radioactive waste generated is usually lower for decommissioning plants than for operating plants, the quantity of solid LLW being generated is significantly higher during decommissioning.

Solid waste is packaged in containers to meet the applicable requirements of 49 CFR Parts 171 through 177. Disposal and transportation are performed in accordance with the applicable requirements of 10 CFR Part 61 and 10 CFR Part 71, respectively.

Solid radioactive waste generated during either decommissioning or operations is usually shipped to a LLW processor or, in some cases, directly to a LLW disposal site. Volume reduction may occur both onsite and offsite. The most common onsite volume reduction techniques are high-pressure compacting in waste drums, dewatering and evaporating wet wastes, monitoring waste streams to segregate wastes, and sorting. Offsite waste management vendors compact wastes at ultra-high pressures, incinerate dry active waste, separate and incinerate oily and organic wastes, and asphalt-solidify resins and sludges before the waste is sent to the LLW site.

Nonradioactive wastes, including storm water system and sewage waste, are also generated during the decommissioning process. For example, use of hazardous oils or other chemicals in solvent cleaning and repair of equipment produces some nonradioactive wastes. Also, during decommissioning, additional quantities of nonradioactive waste (paint, asbestos) are generated or removed. Disposal of essentially all of the hazardous chemicals used at nuclear power plants is regulated by the Resource Conservation and Recovery Act (RCRA) of 1976 or by National Pollutant Discharge Elimination System (NPDES) permits, which are regulated by the U.S. Environmental Protection Agency (EPA) and administered by EPA, or if authorized, by the States to control the amount and types of pollutants that may be discharged from the plant.

Mixed waste is regulated under RCRA, the Atomic Energy Act, and NRC and is sent to a facility that is licensed to handle mixed waste.

- <u>Miscellaneous mechanical systems</u>: A variety of existing plant mechanical systems may continue to be used during plant decommissioning, including

  - the fire protection system

  - the heating, ventilation, and air conditioning (HVAC) system

- the fuel-handling system
- various cranes and hoists.

The use of these systems generally does not have a direct impact on the environment. For example, the HVAC system that is used inside a contaminated area would be exhausted to the gaseous waste management system.

- Instrumentation and control systems: While most instrumentation and control systems in the plant can be deactivated after permanent shutdown and defueling of the reactor, a few may continue to be used to support decommissioning operations, including:

  - the radiation monitoring system, which detects, measures, and records radiation levels during decommissioning operations and alerts plant staff of off-normal readings, and
  - the security system, which monitors the plant protected area to prevent uncontrolled access.

  In most cases, these systems are altered or reduced during the decommissioning process. The use of these systems during the decommissioning process does not impact the environment.

- Electrical systems: Numerous electrical systems may continue to be used during decommissioning operations. These include systems needed to provide uninterrupted power, lighting, and communication. In some cases, licensees have installed a new power distribution system, re-energizing only those loads that are necessary for continued use during decommissioning. In many facilities, the circuits that are being used are color-coded so that workers can easily identify the live circuits. Both of these practices are intended to prevent workers from cutting into a live wire during the decommissioning process.

- Spent fuel storage systems: Before beginning the decommissioning process, the licensee must certify to the NRC that it has permanently removed the fuel from the reactor vessel. The fuel is first moved into the spent fuel pool, which is a specially designed water-filled basin. Even after the nuclear reactor is shut down, the fuel continues to generate decay heat from the radioactive decay of fission products. The rate at which the decay heat is generated decreases the longer the reactor has been shut down. Therefore, the longer the time from last criticality, the less heat the spent fuel gives off. Storing the spent fuel in a pool of water provides an adequate heat sink for the removal of heat from the irradiated fuel. In addition, the fuel is located far enough under water that the radiation emanating from the fuel is shielded by the water, thus protecting workers from the radiation. After the

fuel has cooled adequately, it can be stored in an ISFSI in air-cooled dry casks. Typically, transfer of spent fuel to an ISFSI occurs after the fuel has cooled for 5 years.

After removal of the fuel to the spent fuel pool, it is common for the licensee to reduce the security area at the facility to a "nuclear island" that focuses primarily on the storage area for the spent fuel. This allows the spent fuel to be protected and the security system to cover only the storage location for the spent fuel.

At this time, there are no facilities for permanent disposal of high-level radioactive wastes (HLW). The Nuclear Waste Policy Act of 1982 defined the goals and structure of a program for permanent, deep geologic repositories for HLW and unreprocessed spent fuel. Under this Act, the DOE is responsible for developing permanent disposal capacity for the spent fuel and other high-level nuclear wastes. At the present time, DOE, as directed by Congress, is investigating a site in Yucca Mountain, Nevada, for a possible disposal facility. A HLW repository would be built and operated by DOE and licensed by the NRC.

The Commission believes (10 CFR 51.23(a)) there is reasonable assurance that at least one mined geological repository will be available in the first quarter of the 21st Century and that, within 30 years beyond the licensed life of operation for any reactor, sufficient repository capacity will be available to dispose of the reactor's HLW and spent fuel generated up to that time.

Until a HLW repository is available or some interim central waste storage facility is approved and licensed, licensees generally store the fuel onsite, either in dry storage (ISFSI) or in wet storage in a spent fuel pool. Licensees are prohibited from shipping spent fuel from one reactor spent fuel pool to another without NRC approval by license amendment.

The Commission has independently, in a separate proceeding (the Waste Confidence Proceeding), made a finding that there is

> reasonable assurance that, if necessary, spent fuel generated in any reactor can be stored safely and without significant environmental impacts for at least 30 years beyond the licensed life for operation (which may include the term of a revised license) of that reactor at its spent fuel storage basin, or at either onsite or offsite independent spent fuel storage installations (54 FR 39767).

The Commission has committed to review this finding at least every 10 years. In its most recent review, the Commission concluded that experience and developments since 1990 were not such that a comprehensive review of the Waste Confidence Decision was necessary at this time (64 FR 68005). Accordingly, the Commission reaffirmed its findings

of insignificant environmental impacts cited above. This finding is codified in the Commission's regulations at 10 CFR 51.23(a). The staff relies on the Waste Confidence Rule, but for completeness has elected to include in this Supplement information related to the storage and maintenance of fuel in a spent fuel pool.

- Transportation systems: There are four broad classes of shipments to and from operating nuclear power plants: (1) routinely generated LLW transported from plants to disposal facilities, (2) routine LLW shipped to offsite facilities for volume reduction, (3) nuclear fuel shipments from fuel-fabrication facilities to plants for loading into reactors, and (4) spent fuel shipments to other nuclear power plants with available storage space (an infrequent occurrence that is usually limited to plants owned by the same utility).

  The transportation of radioactive materials is regulated jointly at the Federal level by the U.S. Department of Transportation (DOT) and the NRC. The responsibilities of the two agencies are delineated in a Memorandum of Understanding (see 44 FR 38690). Most LLW is shipped in packages authorized by the DOT. Some packages for larger quantities of LLW require NRC certification. The LLW packages can be loaded onto trucks, trains, barges, or other ships for shipment to the LLW disposal site. In general, the areas regulated by the agencies are as follows:

  - DOT – Regulates shippers and carriers of radioactive material and the conditions of transport, including routing, tiedowns, radiological controls, vehicle requirements, hazard communication, handling, storage, emergency response information, and employee training. DOT regulations are located in the Code of Federal Regulations, Title 49, "Transportation."

  - NRC – Regulates users of radioactive material and the design, construction, use, and maintenance of shipping containers used for larger quantities of radioactive material and fissile material such as uranium. NRC regulations are located in 10 CFR Part 71, "Packaging and Transportation of Radioactive Material."

  Title 10 CFR 71.47 states that under normal transportation conditions, each package of radioactive materials must be designed and prepared for shipment such that the radiation level does not exceed 2 mSv/h (200 mrem/h) at any point on the external surface of the package and 0.1 mSv/h (10 mrem/h) at any point 1 m (3.3 ft) from the packaging surface. This type of shipment is called a nonexclusive use shipment. If the package exceeds the limits specified for nonexclusive use shipments, it must be transported by exclusive use shipment only. The radiation limits for exclusive use packages are the following:

- At any point on the package surface: 2 mSv/h (200 mrem/h). For closed transport vehicle only: 10 mSv/h (1000 mrem/h)
- At 2 m (6.6 ft) from lateral surfaces of vehicle: 0.1 mSv/h (10 mrem/h)
- At all external surfaces of the vehicle: 2 mSv/h (200 mrem/h)
- In the occupied area of the vehicle: 0.02 mSv/h (2 mrem/h), with certain exceptions.

For more information regarding waste packaging and radioactive transportation regulations, see 10 CFR Part 71.

The frequency of waste shipments increases sharply during the decommissioning period. In some cases, such as the shipment of large components (e.g., steam generators, reactor vessels, or pressurizers), the waste packaging is unique compared to most shipments during operations. However, the licensee is still required to meet the regulations discussed above, unless the NRC approves an exemption after a thorough analysis of the licensee's proposal.

3.1.4 Formation and Location of Radioactive Contamination and Activation in an Operating Plant

During reactor operation, a large inventory of radioactive fission products builds up within the fuel. Virtually all of the fission products are contained within the fuel pellets. The fuel pellets are enclosed in hollow metal rods, which are hermetically sealed to prevent further release of fission products. Occasionally fuel rods develop small leaks, allowing a small fraction of the fission products to contaminate the reactor coolant. The radioactive contamination in the reactor coolant is the source of gaseous, liquid, and solid radioactive wastes generated at LWRs during operation. Most of the contamination in the reactor coolant system is from the activation of corrosion products and not from leaking fuel.

There are two sources of radioactive material: contamination and activation. Contaminated materials are unintentionally transported through the facility by workers, equipment, and, to some degree, air movement. Although many precautions are taken to prevent the movement of contaminated material in a nuclear facility and to clean up any contaminated materials that may be found, it is likely that contamination will occur in the reactor building, around the spent fuel pool, and around specific SSCs in the auxiliary building and other buildings and equipment in the area near the reactor. The areas known to contain contamination are labeled by the licensee, who routinely checks for contamination and removes as much as possible during operations. Radioactive contamination may be deposited from the air or dissolved in water and subsequently deposited onto material such as concrete. Radioactive contamination is generally

located on or near the surface of materials such as metals, high-density concrete, or painted walls. It can travel farther into unpainted surfaces or lower-density concrete. Radioactive contamination can usually be removed from surface areas by washing, scrubbing, spraying, or, in extreme cases, by physically removing the outer layers of the surface material.

Activation products are also formed during reactor operation. Activation products are radioactive materials created when stable substances are bombarded by neutrons. Concrete and steel surrounding the core of the reactor are the most common types of activated products. Activation products cannot be removed by the processes used to remove contamination. Activation products are incorporated into the molecular structure of the material and cannot be wiped off or removed. The entire structure (or portions) that have been activated must be removed and treated as radioactive waste. Activated metal and concrete contain the single largest inventory of radionuclides with the exception of the spent fuel, in facilities that are being decommissioned. The radioactive decay of activation products, both of structures as well as corrosion products, is the main source of radiation exposure to plant personnel.

The spent fuel contains the largest amount of radioactive material at a permanently shutdown facility followed by the reactor vessel, internals, and bioshield. Systems containing smaller amounts of radioactive material include the steam generator, pressurizer, piping of the primary system and other systems, piping, as well as the radwaste systems. Minor contamination is found in the secondary systems and miscellaneous piping.

3.2 Decommissioning Options

This Supplement evaluates the environmental impacts of three decommissioning options or combinations of the options. These options, first identified in the 1988 Generic Environmental Impact Statement (GEIS) using the acronyms DECON, SAFSTOR, and ENTOMB, are defined as follows:

DECON: The equipment, structures, and portions of the facility and site that contain radioactive contaminants are promptly removed or decontaminated to a level that permits termination of the license shortly after cessation of operations.

SAFSTOR: The facility is placed in a safe, stable condition and maintained in that state (safe storage) until it is subsequently decontaminated and dismantled to levels that permit license termination. The determination of SAFSTOR includes those activities necessary for the final decontamination and dismantlement of the facility. During SAFSTOR, a facility is left intact, but the fuel has been removed from the reactor vessel, and radioactive liquids have been drained from systems and components and then processed. Radioactive decay

occurs during the SAFSTOR period, thus reducing the quantity of contaminated and radioactive material that must be disposed of during decontamination and dismantlement. The definition of SAFSTOR also includes the decontamination and dismantlement of the facility at the end of the storage period.

ENTOMB: Radioactive SSCs are encased in a structurally long-lived substance, such as concrete. The entombed structure is appropriately maintained, and continued surveillance is carried out until the radioactivity decays to a level that permits termination of the license.

The choice of decommissioning option is left entirely to the licensee, provided that it can be performed according to the NRC's regulations. This choice is communicated to the NRC and the public in the post-shutdown decommissioning activities report (PSDAR). In addition, the licensee may choose to combine the DECON and SAFSTOR options. For example, after power operations cease at a facility, a licensee could use a short storage period for planning purposes, followed by removal of large components (such as the steam generators, pressurizer, and reactor vessel internals), place the facility in storage for 30 years, and eventually finish the decontamination and dismantlement process.

Although the selection of the decommissioning option is up to the licensee, the NRC requires the licensee to re-evaluate its selection if the option (1) could not be completed as described, (2) could not be completed within 60 years of the permanent cessation of plant operations, (3) included activities that would endanger the health and safety of the public by being outside of the NRC's health and safety regulations, or (4) would result in a significant impact to the environment.

To date, most utilities have used DECON or SAFSTOR to decommission reactors. Several sites have performed some incremental decontamination and dismantlement during the storage period of SAFSTOR, a combination of SAFSTOR and DECON. A site using DECON may have a short period of time (1 to 4 years) when the facility is in SAFSTOR. Several licensees continue to conduct limited decommissioning activities during a SAFSTOR period as personnel, money, or other factors become available. This process of occasionally conducting active decontamination and dismantlement is referred to as incremental DECON. No utilities have used the ENTOMB option for a commercial nuclear power reactor.

The following sections provide a general overview of each decommissioning option.

3.2.1 DECON

The DECON decommissioning option involves removing or decontaminating equipment, structures, and portions of the facility and site that contain radioactive contaminants to a level that permits termination of the license, as defined in Regulatory Guide 1.184 (NRC 2000a).

There are several advantages to using the DECON option of decommissioning. One is that the facility license is quickly terminated so that the facility and site become available for other purposes. By beginning the decontamination and dismantlement process soon after permanent cessation of operation, the available work force can be maintained and is highly knowledgeable about the facility. The availability of facilities willing to accept LLW may also be a factor in the licensee's decision to pursue the DECON option. Currently, the estimated cost of decommissioning a site using DECON is less than SAFSTOR due primarily to price escalation in the disposal of LLW. Because most activities that occur during DECON also occur during SAFSTOR, the price for decommissioning at a later date is greater because of the cost of storage and inflation (NRC 2000c). DECON also eliminates the need for long-term security, maintenance, and surveillance of the facility (excluding the onsite storage of spent fuel), which is required for the other decommissioning options.

The major disadvantages of DECON are the higher worker dose and significant initial expenditures. Also, compared to SAFSTOR, DECON requires a larger potential commitment of disposal site space (NRC 2000c).

The general activities that may occur during DECON are listed below (NRC 2000d):

- draining (and potentially flushing) of some contaminated systems and removal of resins from ion exchangers
- setup activities such as establishing monitoring stations or designing and fabricating special shielding and contamination-control envelopes to facilitate decommissioning activities
- reduction of site-security area (setup of new security monitoring stations)
- modification of the control room or establishing an alternate control room
- site surveys
- decontamination of radioactive components, including use of chemical decontamination techniques

- removal of reactor vessel and internals
- removal of other large components, including major radioactive components
- removal of the balance of the primary system (charging system, boron control system, etc.)
- general activities related to removing other significant radioactive components
- decontamination and/or dismantlement of structures or buildings
- temporary onsite storage of components
- shipment and processing of LLW, including compaction or incineration of the waste
- removal of the spent fuel and Greater-than-Class-C (GTCC) Waste to an ISFSI
- removal of hazardous radioactive (mixed) wastes
- changes in management and staffing.

3.2.2 SAFSTOR

The SAFSTOR decommissioning option involves placing the facility in a safe, stable condition and maintaining that state for a period of time, followed by subsequent decontamination and dismantlement to levels that permit license termination. During the storage period of SAFSTOR, the facility is left intact. The fuel has been removed from the reactor vessel and radioactive liquids have been drained from systems and components and processed. Radioactive decay occurs during the storage period, reducing the quantity of contaminated and radioactive material that must be disposed of during decontamination and dismantlement.

There are several advantages to using the SAFSTOR option of decommissioning. A substantial reduction in radioactive material as a result of radioactive decay during the storage period reduces worker and public doses below those of the DECON alternative. Since there is potentially less radioactive waste, less waste-disposal space is required. Moreover, the costs immediately following permanent cessation of operations are lower than costs during the first years of DECON because of reduced amounts of activity and a smaller work force (NRC 2000c).

However, because of the time gap between cessation of operations and decommissioning activities, SAFSTOR can result in a shortage of personnel familiar with the facility at the time of dismantlement and decontamination. During the prolonged period of storage, the plant requires continued maintenance, security, and surveillance. Also, uncertainties regarding the availability and cost of LLW sites in the future could mean higher costs for decontamination and dismantlement (NRC 2000c).

Activities that typically occur during the preparation and storage stages of the SAFSTOR process are described below (NRC 2000d).

<u>During preparation</u>:

- draining (and potential flushing) of some systems and removal of resins from ion exchangers
- spent fuel pool cooling systems reconfiguration
- decontamination of highly contaminated and high dose areas as necessary
- performance of a radiological assessment as a baseline before storage
- removal of LLW that is ready to be shipped
- shipment and processing or storage of the fuel and GTCC waste
- de-energizing or deactivating systems and equipment
- reconfiguration of ventilation systems, fire protection systems, and spent fuel pool cooling system for use during storage
- establishment of inspection and monitoring plans for use during storage
- maintenance of any systems critical to final dismantlement during storage
- changes in management and staffing.

<u>During storage</u>:

- performance of preventative and corrective maintenance on plant systems that will be operating and/or functional during storage

- maintenance to preserve structural integrity
- maintenance of security systems
- maintenance of radiation effluent and environmental monitoring programs
- processing of any radwaste generated (usually small amounts).

Following the storage period, the facility is decontaminated and dismantled to radiological levels that allow termination of the license. Activities during this period of time will be the same activities that occur for DECON.

3.2.3 ENTOMB

The ENTOMB decommissioning method was defined in the Supplementary Information to the 1988 Decommissioning Rule (53 FR 24018) as the option in which radioactive contaminants are encased in a structurally long-lived material, such as concrete. The entombed structure is appropriately maintained and surveillance is continued until the radioactivity decays to a level permitting unrestricted release of the property (NRC 1988).

Currently, 10 CFR 50.82 (a)(3) requires that decommissioning be completed within 60 years of permanent cessation of operations, and completion of decommissioning beyond 60 years be approved by the NRC only when necessary to protect public health and safety. The factors that could be considered by the Commission in evaluating an option that provides for the completion of decommissioning beyond 60 years of permanent cessation of operation include unavailability of waste disposal capacity and site-specific factors affecting the licensee's capability to carry out decommissioning, including the presence of other nuclear facilities at the site.

The current regulations, pertaining to the decommissioning of nuclear reactors promulgated in 1988, are also structured to favor decommissioning options that result in unrestricted release of the site. As noted in the supplementary information for the June 27, 1988, final rule, the ENTOMB option was not specifically precluded because it was recognized that it might be an allowable option for protecting public health and safety.

The 1997 Rule for Radiological Criteria for License Termination (64 FR 39058) established criteria (10 CFR Part 20, Subpart E) that allow for both restricted and unrestricted release of property. Under a restricted release, the dose to the average member of the critical group must not exceed 0.25 mSv/yr (25 mrem/yr) total effective dose equivalent (TEDE) and must be as low as reasonably achievable (ALARA) with the restrictions in place. If the restrictions were no longer in effect, the dose due to residual radioactivity could not exceed 1 mSv/yr (100 mrem/yr)

(or 5 mSv/yr [500 rem/yr], if additional conditions are met) TEDE and must be ALARA. These caps were chosen to provide a safety net in the highly unlikely event that the restrictions failed.

In the Staff Requirements Memorandum on the ENTOMB option, dated July 20, 2000 (NRC 2000b), the Commission directed that

> [T]he staff closely coordinate this rulemaking effort for this rulemaking with the ongoing efforts to update the generic environmental impact statement for the decommissioning of power reactors. The staff should include the entombment option in the GEIS recognizing that not all entombment proposals can be forecast but that the GEIS would provide a bounding analysis. The staff should also address the issue of entombing Greater Than Class C waste for this category of waste.

On September 18, 2001, the Commission approved the staff's rulemaking plan (see Section 2.2.2) for potential development of a rule to allow entombment as a decommissioning option for power reactors. NRC published an Advance Notice of Proposed Rulemaking (ANPR) on October 16, 2001 (66 FR 52551) seeking stakeholder input on three proposed regulatory options and whether entombment was a viable decommissioning alternative. The ANPR comment period closed on December 31, 2001. NRC received 19 comments from: six States; eight licensees; the Nuclear Energy Institute (NEI); the U.S. Environmental Protection Agency (EPA); the Conference of Radiation Control Program Directors' E-24 Committee on Decommissioning and Decontamination (CRCPD E-24 Committee); the Southeast Compact Commission (SCC); and a private individual.

Generally, the eight utilities and NEI stated that they would have entombment available as a decommissioning option; however, none unequivocally committed to using entombment for their decommissioning process. Some Agreement State commenters endorsed the 10 CFR Part 20 dose limits, with one State adding that a time limit to reach the dose rates should be considered. Although one State advocated extending the decommissioning period beyond 60 years, most were silent on the decommissioning regulations in 10 CFR Part 50. The staff notes that there was no consensus on a preferred option. NRC staff has considered the comments received and has prepared a paper transmitting the staff's recommendations to the Commission. As of the date of this publication the Commission has not acted on the staff's recommendations.

The assessment of impacts associated with the ENTOMB option presented in this GEIS is independent of a prospective rulemaking before the Commission. The staff is making the assumption that environmental issues arising from any rulemaking effort will be addressed in the rulemaking and its supporting environmental documentation. These issues may include: (1) the long-term onsite retention of radioactive materials, including those that may be classified

as GTCC, (2) issues related to long-term NRC oversight and monitoring requirements, (3) durability of institutional controls and site-engineered barriers, and (4) site-specific requirements.

The purpose of the entombment process is to isolate the entombed radioactive waste so that the reactor facility can be released and the license terminated. Therefore, prior to entombment, (1) an accurate characterization of the radioactive materials that are to remain is needed, and (2) the adequacy of the entombment configuration to isolate the entombed radioactive waste must be determined. Because of the requirement in the regulation to complete decommissioning within 60 years, no licensee has proposed the use of ENTOMB as the preferred decommissioning option for any of the nuclear power reactors currently undergoing decommissioning. The staff can envision a large number of entombment scenarios arranged along a continuum, differing primarily on the amount of decontamination and dismantlement done prior to the actual entombment.

The staff evaluated the impacts associated with the entombment options by developing two scenarios that have been designated ENTOMB1 and ENTOMB2. These two scenarios were developed specifically to envelope a wide range of potential options by describing two possible extreme cases of entombment. ENTOMB1 assumes significant decontamination and dismantlement and removal of all contamination and activation involving long-lived radioactive isotopes prior to entombment. ENTOMB2 assumes significantly less decontamination and dismantlement, significantly more engineered barriers, and the retention onsite of long-lived radioactive isotopes. Both options assume that the spent fuel would be removed from the facility and either transported to a permanent HLW repository or placed in an onsite ISFSI. Licensees choosing ENTOMB will adapt the entombment option to fit their specific site requirements.

ENTOMB1 is envisioned by the staff to begin the decommissioning process in a manner similar to the DECON option. The reactor would be defueled and the fuel initially placed into the spent fuel pool for some period prior to disposal at a licensed HLW repository or placed in an onsite ISFSI. Any decommissioning activity would be preceded by an accurate radiological characterization of SSCs throughout the facility. Active decommissioning would begin with draining and decontamination of SSCs throughout the facility with the goal of isolating and fixing contamination. SSCs would either be decontaminated or removed and either shipped to a LLW burial site or placed inside the reactor containment building. Offsite disposal of resins and considerable amounts of contaminated material would occur. There would likely be a chemical decontamination of the primary system. The reactor pressure vessel (RPV) and reactor internals would be removed, either intact or after sectioning, and disposed of offsite.

Any other SSCs that have long-lived activation products would be removed. Interim dry storage of the vessel, vessel internals, and any other SSCs containing long-lived activation products could occur onsite until a final disposal site for this waste (predominately GTCC waste) is identified. Steam generators and the pressurizer, depending on whether or not the components are contaminated with long-lived radioisotopes, would either be removed and disposed of offsite or retained inside the reactor containment. The spent fuel pool would be drained and decontaminated. The reactor building or containment would then be filled with SSCs

contaminated with relatively short-lived isotopes from the balance of the facility. Material would be placed in the building in a manner that would minimize the spread of any contamination (i.e., dry, contamination fixed, isolated). Engineered barriers would be put in place to deny access and eliminate the possibility of the release of any contamination to the environment. The reactor building or containment would be sealed and made weather tight.

The license termination monitoring program would be submitted and the site would be characterized. A partial site release would be completed for almost all of the site and the balance of the plant. The staff makes no assumptions as to when the license would be terminated and whether it would be terminated under the restricted or unrestricted provisions of 10 CFR Part 20, Subpart E. These decisions would likely be addressed as part of the staff's rulemaking effort related to entombment, explained above. The staff does assume that there would be a monitoring program period as long as 20 to 30 years to demonstrate that there was isolation of the contamination and adequate permanence of the structure.

The general activities that would occur during ENTOMB1 are listed below:

- planning and preparation activities
- draining (and potentially flushing) of contaminated systems and removal of resins from ion exchangers
- reduction of site-security area (optional)
- deactivation of support systems
- decontamination of radioactive components, including use of chemical decontamination techniques
- removal of the reactor vessel and internals
- removal of other large components, including major radioactive components

- removal of fuel from the spent fuel pool to an ISFSI
- dismantlement of remaining radioactively contaminated structures and placement of the dismantled structures in the reactor building
- installation of engineered barriers and other controls to prevent inadvertent intrusion and dispersion of contamination outside of the entombed structure
- filling of the void spaces in the previous reactor building structure with grout (concrete).

ENTOMB2 is also envisioned by the staff to begin the decommissioning process in a manner similar to the DECON option. The reactor would be defueled and the fuel initially placed into the spent fuel pool for some period prior to disposal at a licensed HLW repository or placed in an onsite ISFSI. Any decommissioning activity would be preceded by an accurate radiological characterization of SSCs throughout the facility. Active decommissioning would begin with the draining and decontamination of SSCs throughout the facility with the goal of isolating and fixing contamination. The spent fuel pool would be drained and decontaminated. SSCs would either be decontaminated or removed and either shipped to a LLW burial site or placed inside the reactor containment building (PWR) or the reactor building (BWR). Disposal offsite of resins would occur. The primary system would be drained, the RPV filled with contaminated material, all penetrations sealed, the RPV head reinstalled, and the reactor vessel filled with low-density concrete. Reactor internals would remain in place. Emphasis would be placed on draining and drying all systems and components and fixing contamination to prevent movement, either by air or liquid means. The steam generators and pressurizer would be laid up dry and remain in place. The reactor building or containment would then be filled with contaminated SSCs from the balance of the facility. Material would be placed in the building in a manner that would minimize the spread of any contamination (i.e., dry, contamination fixed, isolated).

Engineered barriers would be put in place to deny access and eliminate the possibility of the release of any contamination to the environment. The ceiling of the containment or reactor building, in the case of BWRs, may be lowered to near the refueling floor and to the top of the pressurizer for PWRs. The cavity of the remaining structure would be filled with a low-density concrete. The resulting structure would be sealed and made weather tight and covered with an engineered cap designed to deny access, and prevent the intrusion of water or the release of radioactive contamination to the environment.

The license termination monitoring program would be submitted and the site would be characterized. A partial site release would be completed for almost all of the site and the balance of the plant. The license would be likely terminated under the restricted release

provisions of 10 CFR Part 20, Subpart E, after a site-monitoring program that demonstrates the isolation of the contamination and the permanence of the structure. Monitoring could be as long as 100 years.

The general activities that would occur during ENTOMB2 are listed below:

- planning and preparation activities
- draining (and potentially flushing) of contaminated systems and removal of resins from ion exchangers
- deactivation of support systems
- removal of fuel from the spent fuel pool to an ISFSI
- dismantlement of all radioactively contaminated structures (other than the reactor building) and placement of the dismantled structures in the reactor building
- potentially lowering of the ceiling of the reactor building to near the refueling floor (in BWRs) or near the top of the pressurizer (in PWRs)
- installation of engineered barriers and other controls to prevent inadvertent intrusion and dispersion of contamination outside of the entombed structure
- filling of the cavity of the reactor building structure with low-density concrete
- placement of an engineered cap over the entombed structure to further isolate the structure from the environment.

The advantages of both ENTOMB options are reduced public exposure to radiation due to significantly less transportation of radioactive waste to an LLW disposal site and corresponding reduced cost of LLW disposal. An additional advantage of ENTOMB2 is related to the significant reduction in the amount of work activity, and thus a significant reduction in occupational exposures, as compared to the DECON or SAFSTOR decommissioning options.

3.3 Summary of Plants That Have Permanently Ceased Operations

Twenty-two of the commercial nuclear reactors licensed by the NRC have permanently shut down and have had their licenses terminated or are currently being decommissioned. This section presents the significant characteristics of these plants, the decommissioning options being used by each plant, and each plant's decommissioning activities.

3.3.1 Plant Sites

An overview of the shutdown plants can be found in Table 3-1, which includes 22 units shut down between 1963 and 1997. Table 3-2 summarizes important characteristics of the shutdown plants. The thermal power capabilities of the reactors ranged from 23 to 3411 MW(t). The reactors operated from just a few days (Shoreham) to 33 years (Big Rock Point). Since 1987, an average of one plant per year has been shut down.

Three of the 22 plants (Fort St. Vrain, Shoreham, and Pathfinder) have completed decommissioning and have had their 10 CFR Part 50 licenses terminated. Two of these three (Fort St. Vrain and Shoreham) used the DECON process for decommissioning. One facility, Shoreham, operated less than three full power days before being shut down and decommissioned so there was relatively little contamination. Another facility, Pathfinder, was placed in SAFSTOR and subsequently decommissioned. Eleven of the plants shut down prematurely. Three Mile Island, Unit 2, ceased power operations as a result of a severe accident. Three Mile Island, Unit 2, has been placed in a monitored storage mode until Unit 1 permanently ceases operation, at which time both units are to be decommissioned.

Eleven of the permanently shutdown plants were part of the U.S. Atomic Energy Commission's (AEC's) Demonstrations Program, including Big Rock Point; Dresden, Unit 1; Fermi, Unit 1; GE-VBWR; Humboldt Bay, Unit 3; Indian Point, Unit 1; La Crosse; Pathfinder; Peach Bottom, Unit 1; Yankee Rowe; and Saxton. These plants were prototype designs that were jointly funded by the AEC and commercial utilities. One of the plants, Pathfinder, has completed decommissioning and had its license terminated.

The most recent of the Demonstration Program reactors to shut down was Big Rock Point, which operated for 33 years and permanently shut down in 1997.

Table 3-1. Summary of Shutdown Plant Information

Types and Number of Shutdown Reactors	
BWR	8
PWR	11
HTGR	2
FBR	1
Decommissioning Option	
SAFSTOR	14
DECON	7
Accident cleanup followed by storage	1
Fuel Location	
Fuel onsite in pool	13
No fuel onsite[a]	8
Fuel onsite in ISFSI	1
Plan to move fuel to an ISFSI between 2000 and 2005	9

(a) Includes Three Mile Island, Unit 2, which has approximately 900 kg of fuel remaining onsite due to the accident.

Eight of the decommissioned or decommissioning plants are located in the northeast (or mid-Atlantic states), six in the west, six in the midwest, and one in the east. The majority of the shutdown plants (13) are situated on freshwater or impoundments, five others are in coastal or estuarine environments, and three others are on the Great Lakes.

3.3.2 Description of Decommissioning Options Selected

Seven decommissioned units are located on multi-unit sites in which the remaining units continue to operate and one multi-unit site shut down both units permanently. All eight of these licensees chose SAFSTOR as the decommissioning option. In most cases, SAFSTOR was chosen so that all units on a site could be decommissioned simultaneously. For various reasons, however, most shutdown units have done some decontamination and dismantlement.

The reasons cited by licensees for choosing DECON have included the availability of LLW capacity, availability of staff familiar with the plant, available funding, the licensee's intent to use the land for other purposes, influence by State or local government to complete decommissioning, or a combination of other reasons.

A number of the plants have combined the DECON and SAFSTOR process by either entering shorter SAFSTOR periods or by doing an incremental DECON, allowing the plant to use resources and "decommission as they go." Sites have combined the options, usually to achieve

economic advantages. For example, one site decided to shorten the SAFSTOR period and begin incremental dismantlement out of concern over future availability of a waste site and future costs of disposal. One site that prematurely shut down had a short SAFSTOR period to allow short-lived radioactive materials to decay and to conduct more detailed planning. Safety is another reason for combining the two options. Because of seismic safety concerns, one site undertook a major dismantling project to remove a 76-m (250-ft) concrete vent stack after it had been in SAFSTOR for 10 years.

The licensee determines the physical condition of the site after the decommissioning process. Some licensees intend to restore the site to "greenfield" status at the end of decommissioning, while others may install a non-nuclear facility. The NRC's regulatory authority is only over that portion of the facility that is contaminated. Some licensees will leave structures standing at the time of license termination, and others will not. While undergoing the decommissioning process, some licensees have opted for partial site release to decrease the size of the site area.

3.3.3 Decommissioning Process

The processes of decommissioning a power reactor facility for the SAFSTOR and DECON options can be divided into four stages, as shown in Figure 3-3. Figure 3-4 identifies the comparable stages that could be postulated for the two ENTOMB options. The order of each step and the duration of each stage vary, depending on plant-specific characteristics, such as location, operating history, reactor vendor, and licensee. The staff considered the differences in timing and choice of activities in evaluating the environmental impacts of decommissioning based on the experiences of currently decommissioning facilities.

Stage 1 in Figures 3-3 and 3-4 includes the licensee's initial preparations to shut down the plant and begin decommissioning. This stage is primarily administrative. Stage 1 typically lasts 1½ to 2½ years, regardless of the decommissioning option chosen. The main activities during the planning and preparation stage are determining the decommissioning option, making changes to the organization structure (layoffs, hiring experienced decommissioning contractors, etc.), and initiating licensing-basis changes.

The planning and preparation activities of Stage 1 vary, depending on when the licensee decides to cease operation. If the end of service is planned, the licensee may make plans for the decommissioning process and may even submit the PSDAR in advance of shutdown. This allows the plant to start major decommissioning activities immediately following the certification of permanent shutdown and the removal of the fuel (see Chapter 2, "Background Information

Related to Decommissioning Regulations," for a discussion of major decommissioning activities). If the end of service is unplanned, the licensee will probably not be ready to start decommissioning activities immediately following the certification of permanent shutdown and removal of fuel. Therefore, the order and duration of the activities in Stage 1 might vary compared to a planned shutdown. For most plants, the organizational changes will include a reduction in the number of staff as well as implementation of an employee-retention program to encourage the needed staff to stay on. However, one site actually had to increase staffing levels at the time of the permanent cessation of operation to start the DECON process. Initial plant characterization will be made during the planning activities and will continue throughout the decommissioning process. Because these activities are mostly planning, administrative, and organizational in nature, there is little potential for onsite or offsite impacts from these activities and only small amounts of decommissioning-related LLW generated.

Stage 2 in Figures 3-3 and 3-4 involves the transition of the plant from reactor operation to decommissioning. Stage 2 will last from about ½ to 1½ years for plants in SAFSTOR, DECON, and ENTOMB. All plants will have to transfer fuel out of the reactor and into the spent fuel pool. Isolation and stabilization of all unnecessary SSCs are also conducted during this stage.

Licensing-basis changes will continue during this stage, and the licensee may request an exemption from offsite emergency preparedness requirements.

For DECON and SAFSTOR, there are a number of activities during Stage 2 that the plant can either choose not to perform or can perform at a later date. Chemical decontamination of the primary system and creation of a nuclear island are the two main activities that several decommissioning sites have undertaken. Chemical decontamination is optional for ENTOMB1 and would not likely occur for ENTOMB2. Support systems no longer necessary to reactor operation may also be removed for all four options. Likewise, additional support systems needed for decommissioning activities may be installed at this stage for DECON, SAFSTOR, and ENTOMB1. Changes to electrical systems are common during Stage 2.

Chemical decontamination of the primary system has been performed at several facilities, resulting in a reduction of total person-rem during decommissioning activities. One facility evaluated conducted a system decontamination, aiming at significant reduced dose to workers and reduced cost, by reducing both the amount and level of contamination from disposal of contaminated piping. This chemical decontamination was performed following the removal of the steam generators, pressurizer, and reactor coolant pump motors, as well as most of the

Table 3-2. Permanently Shutdown Plants

Nuclear Plant	Reactor Type	Thermal Power	Shutdown Date [a]	Decommissioning Option[b]	Location	Fuel Status and License Termination Date
Plants Currently in Decommissioning Process						
Big Rock Point	BWR	240 MW	08/30/97	DECON	Michigan	Fuel in pool
Dresden, Unit 1	BWR	700 MW	10/31/78	SAFSTOR	Illinois	Fuel in ISFSI
Fermi, Unit 1	FBR	200 MW	09/22/72	SAFSTOR[c]	Michigan	No fuel onsite
GE-VBWR	BWR	50 MW	12/09/63	SAFSTOR	California	No fuel onsite
Haddam Neck	PWR	1825 MW	07/22/96	DECON	Connecticut	Fuel in pool
Humboldt Bay, Unit 3	BWR	200 MW	07/02/76	SAFSTOR[c]	California	Fuel in pool
Indian Point, Unit 1	PWR	615 MW	10/31/74	SAFSTOR	New York	Fuel in pool
La Crosse	BWR	165 MW	04/30/87	SAFSTOR	Wisconsin	Fuel in pool
Maine Yankee	PWR	2700 MW	12/06/96	DECON	Maine	Fuel in pool[d]
Millstone, Unit 1	BWR	2011 MW	11/04/95	SAFSTOR	Connecticut	Fuel in pool
Peach Bottom, Unit 1	HTGR	115 MW	10/31/74	SAFSTOR	Pennsylvania	No fuel onsite
Rancho Seco	PWR	2772 MW	06/07/89	SAFSTOR[c]	California	Fuel in ISFSI/Partial DECON proposed in 1997
San Onofre, Unit 1	PWR	1347 MW	11/30/92	SAFSTOR[c]	California	Fuel in pool
Saxton	PWR	28 MW	05/01/72	SAFSTOR[c]	Pennsylvania	No fuel onsite/Currently in DECON
Three Mile Island, Unit 2	PWR	2772 MW	03/28/79	Accident cleanup followed by storage	Pennsylvania	Approx 900 kg fuel onsite/ Post-defueling monitored storage
Trojan	PWR	3411 MW	11/09/92	DECON	Oregon	Fuel in pool
Yankee Rowe	PWR	600 MW	10/01/91	DECON	Massachusetts	Fuel in pool[d]
Zion, Unit 1	PWR	3250 MW	02/21/97	SAFSTOR	Illinois	Fuel in pool
Zion, Unit 2	PWR	3250 MW	09/19/96	SAFSTOR	Illinois	Fuel in pool
Terminated Licenses						
Fort St. Vrain	HTGR	842 MW	08/18/89	DECON	Colorado	Fuel in ISFSI/License terminated in 1997
Pathfinder	BWR	190 MW	09/16/67	SAFSTOR	South Dakota	No fuel onsite/License terminated in 1992
Shoreham	BWR	2436 MW	06/28/89	DECON	New York	No fuel onsite/License terminated in 1995

(a) The shutdown date corresponds to the date of the last criticality.
(b) The option shown in the table for each plant is the option that has been officially provided to NRC. Plants in DECON may have had a short (1 to 4 yr) SAFSTOR period. Likewise, plants in SAFSTOR may have performed some DECON activities or may have transitioned from the storage phase into the decontamination and dismantlement phase of SAFSTOR.
(c) These plants have recently performed or are currently performing the decontamination and dismantlement phase of SAFSTOR.
(d) Licensee is in process of transferring fuel to dry storage in onsite ISFSI.

auxiliary piping. At a second facility evaluated, a chemical decontamination was considered necessary to keep doses within previously issued EAs. The chemical decontamination was performed early in the decommissioning process to allow dismantling to proceed unimpeded. Other plants, both operating and permanently shutdown, have also performed chemical decontamination.

Some plants have also created nuclear islands, which reduce the scope of the required safeguards and security systems to only the fuel storage facilities and isolate the spent fuel so decontamination and dismantlement can proceed on the balance of the facility without the potential for affecting the spent fuel. Creating a nuclear island may involve installing an electrical power supply at the spent fuel pool, installing or modifying chemistry controls, designing and constructing a new heat removal system, and moving or installing new security-related equipment. For plants going into SAFSTOR, creation of a nuclear island is primarily a cost savings, but for plants in active decontamination and dismantlement, work activities may be done more conveniently when workers are not constrained by security requirements. ENTOMB2 would not benefit from the "nuclear island" concept.

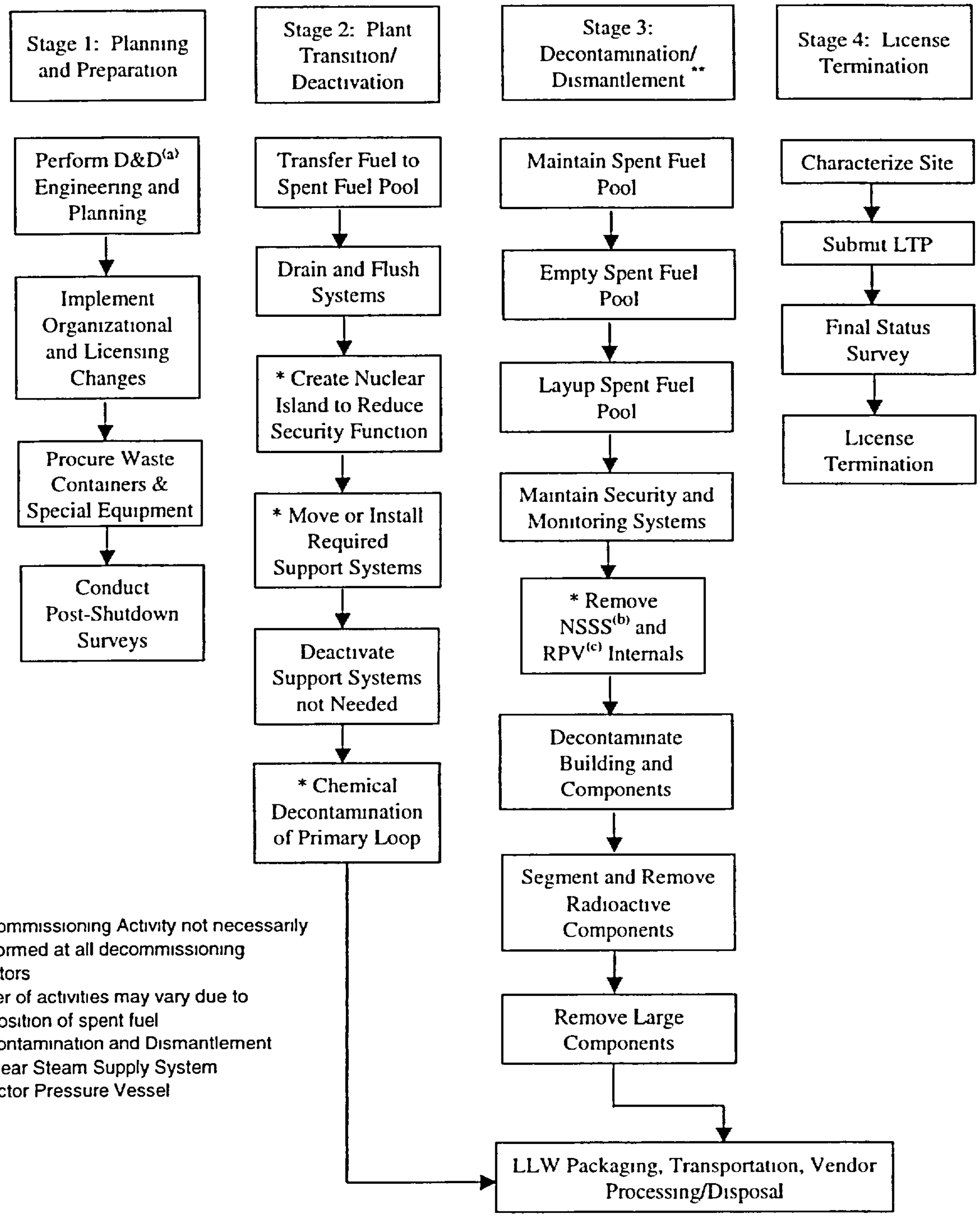
Environmental impacts may vary at each site, depending on the activities and the timing of the activities performed. Examples of impacts include activities such as chemical decontamination, which result in the use of small quantities of water and produce LLW as well as some liquid effluents that would not be released unless they are below the limits allowed by the regulations in 10 CFR Part 20. Smaller amounts of waste will likely be generated during the creation of a nuclear island or the rewiring of a facility.

Stage 3 in Figure 3-3 involves decontamination and dismantlement of the plant for DECON, SAFSTOR, and ENTOMB1. For ENTOMB2, Stage 3 involves dismantlement of all radioactively contaminated SSCs external to the reactor building and placement of these SSCs in the reactor building, followed by lowering the ceiling to the D-rings (PWRs) or refueling floor (BWRs). For both ENTOMB options, it includes installation of concrete and engineered barriers and development of the license termination monitoring program. For those sites that have a SAFSTOR period, Stage 3 includes the storage time. The decontamination and dismantlement activities performed for SAFSTOR can occur before, after, or during the storage period. For the SAFSTOR period, Stage 3 can be from just a few years to about 54 years. For a site going straight through the DECON option, the time for Stage 3 would be expected to take between 3½ and 10 years. For either ENTOMB option Stage 3 would be expected to take 2 to 4 years

The greatest variability in the decommissioning process is seen in Stage 3 and is related to dismantlement. Every plant that has completed decommissioning or has started dismantlement has performed the activities in different ways and at different times during the decommissioning

process. Two examples of large-component removal are at Rancho Seco and Trojan. Rancho Seco has started its dismantlement on the secondary side, removing the moisture separators, diesel generators, steam piping, and related components. Dismantlement of the equipment in the auxiliary building was also initiated. Plans for large-component removal are still in process. The primary issues related to decisions on large-component removal are how to transport the components. Because there are no convenient waterways for transport, the large components from Rancho Seco will have to be shipped by both road and rail, which will require segmentation or cutting up the larger components. Trojan took a different approach to dismantlement, based on the ability to ship by barge and the availability of disposal at Hanford. Trojan removed its four steam generators and pressurizer, pumped grout into them, and shipped them by barge for burial at Hanford. Following that activity, the reactor vessel and internals were removed whole, filled with grout, welded closed, and shipped. For Trojan, removing and shipping these large components as whole units saved millions of dollars and significantly reduced dose to workers.

Stage 4 of decommissioning is license termination. Activities for this stage, which are similar for all options, include final site characterization, final radiation survey submission of final license termination plan, and final site survey. The ENTOMB options would include both a partial site release and a site monitoring program.



* Decommissioning Activity not necessarily performed at all decommissioning reactors
** Order of activities may vary due to disposition of spent fuel
(a) Decontamination and Dismantlement
(b) Nuclear Steam Supply System
(c) Reactor Pressure Vessel

Figure 3-3. Reactor Decommissioning Process - DECON or SAFSTOR

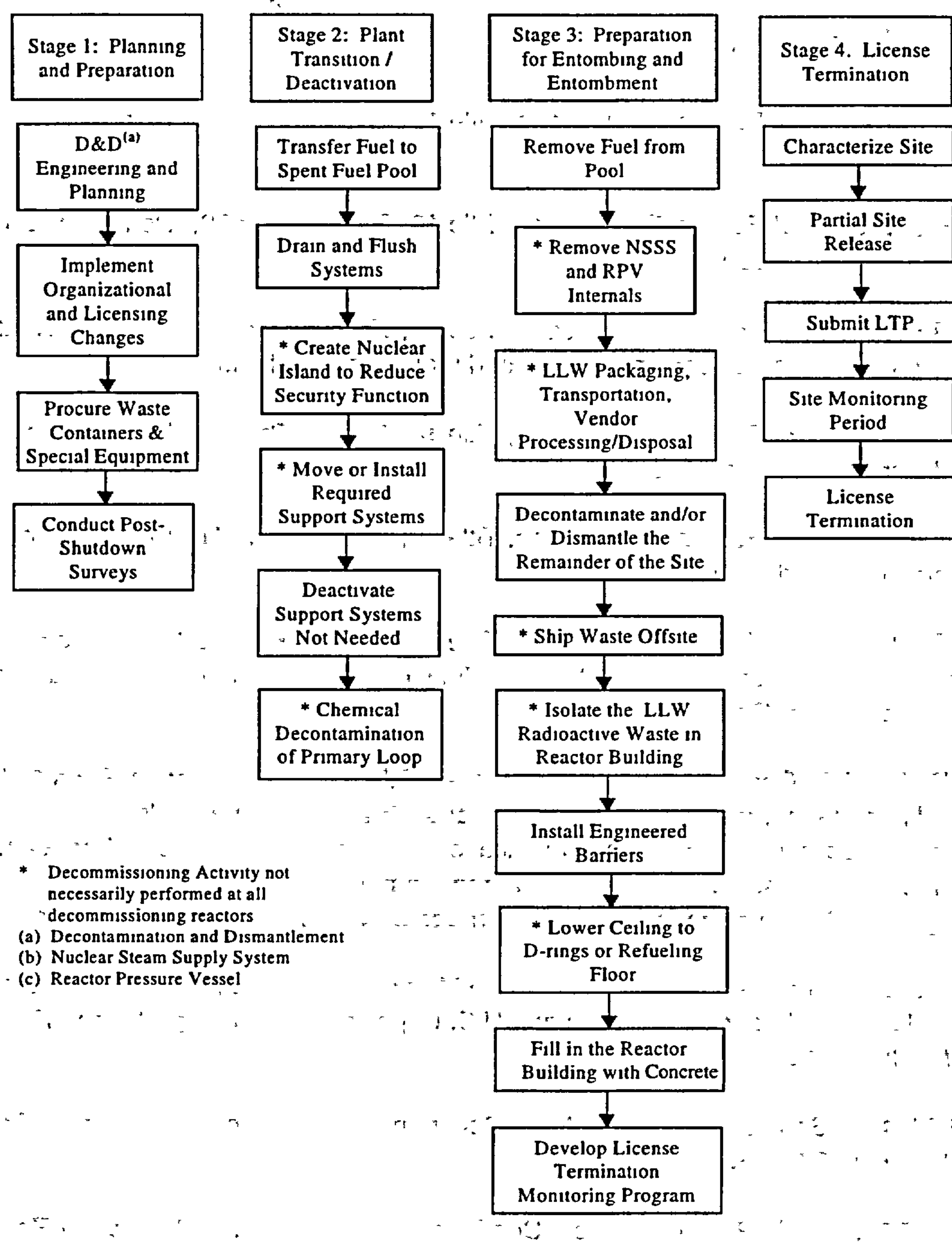


Figure 3-4. Reactor Decommissioning Process - ENTOMB

3.4 References

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4.0 Environmental Impacts of Decommissioning Permanently Shutdown Nuclear Power Reactors

This section discusses the environmental impacts of decommissioning permanently shutdown nuclear power reactor facilities. Section 4.1 defines the terms used to describe environmental impacts of decommissioning activities. Section 4.2 briefly describes the process that was used to identify the environmental impacts of the decommissioning activities. The environmental impacts, including the staff's conclusions, are discussed in Section 4.3.

4.1 Definition of Environmental Impact Standards

This Supplement provides a measure of (1) the significance and severity of potential environmental impacts and (2) the applicability of these decommissioning impacts to a variety of facilities, both permanently shutdown and operating. The significance of each environmental impact is described as SMALL, MODERATE, or LARGE. The applicability of these impacts to a class of plants or site characteristics is categorized as either generic or site-specific. The following sections define the significance and applicability terms used in the Chapter 4 analyses.

4.1.1 Terms of Significance of Impacts

For decommissioning, the staff is using a standard of significance derived from the Council on Environmental Quality (CEQ) terminology for "significantly"[(a)] (40 CFR 1508.27, which considers "context" and "intensity"). The NRC has defined three significance levels: SMALL, MODERATE, and LARGE.

> SMALL – Environmental impacts are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts in this Supplement, the NRC has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

(a) The National Environmental Policy Act of 1969 (NEPA) requires consideration of both *context* and *intensity* when determining the significance of an environmental impact. **Context** means that the significance of an action must be analyzed in several contexts, such as society as a whole (human, national), the affected region, the affected interests, and the locality. Significance varies with the setting of the proposed action. **Intensity** refers to the severity of the impact and depends on many different factors, such as the unique characteristics of the site and the degree to which the proposed action affects public health or safety or may establish a precedent.

MODERATE – Environmental impacts are sufficient to alter noticeably, but not to destabilize, important attributes of the resource.

LARGE – Environmental impacts are clearly noticeable and are sufficient to destabilize important attributes of the resource.

The discussion of each environmental issue in this Supplement includes an explanation of how the significance level was determined. In determining the significance level, the staff assumed that ongoing mitigation measures would continue (including those mitigation measures implemented during plant construction and/or operation) during decommissioning, as appropriate. Additionally, the staff has assumed that a licensee will obtain all relevant permits and appropriate consultations, will continue to comply with the conditions of those permits or consultations, and will use appropriate best management practices (BMPs) to minimize impacts of decommissioning activities. Benefits of additional mitigation measures during or after decommissioning are not considered in determining significance levels.

The cumulative impacts of all activities were assessed. Cumulative impacts are incremental impacts of the decommissioning activity when added to other past, present, and reasonably foreseeable future actions at the licensed site.

4.1.2 Terms of Applicability of Impacts

In addition to determining the significance of environmental impacts, this Supplement includes a discussion of whether the analysis of the environmental issue could be applied to all plants and whether additional mitigation measures would be warranted. Each environmental issue is assigned to one of two categories:

- Generic – For the issue, the analysis reported in this Supplement presents the following:

    (a) Environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues to plants of a specific size, a specific location, or having a specific type of cooling system or site characteristics, and

    (b) A single significance level (i.e., SMALL, MODERATE, or LARGE) has been assigned to the impacts, and

    (c) Mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely not to be sufficiently beneficial to warrant implementation.

- Site-specific – For the issue, the analysis reported in this Supplement has shown that one or more of the generic criteria was not met. Therefore, additional plant-specific review is required. An example of a site-specific issue is threatened and endangered species.

For many issues, similar activities may be performed either on the plant site or offsite. In several cases, the conclusions as to generic or site-specific are different for these locations. In this Supplement, the term "operational areas" are the areas within the protected area fences, the intake and discharge structures, the cooling system, and other site structures, and the associated paved, graveled, and maintained landscaped areas. The operational area is defined as the portion of the plant site where most or all of the site activities occur, such as reactor operation, materials and equipment storage, parking, substation operation, facility service and maintenance, etc.

4.2 Evaluation Process

This section briefly describes the process that the staff used to determine the environmental impacts from decommissioning nuclear power facilities. For a detailed description of this process, see Appendix E, "Evaluation Process for Identifying the Environmental Impacts of Decommissioning Activities." Figure 4-1 is a flowchart showing the evaluation process. Figure 4-1 identifies activities that occur during decommissioning and shows whether the activities affect any of the identified environmental issues. The environmental issues analyzed by the staff are the following: onsite/offsite land use, water use, water quality, air quality, aquatic ecology, terrestrial ecology, threatened and endangered species, radiological, radiological accidents, occupational issues, cost, socioeconomics, environmental justice, cultural impacts, aesthetic issues, noise, transportation, and irretrievable resources. To analyze each issue, the staff used the data obtained from previous studies and environmental reviews, information obtained during site visits and provided by the plants undergoing decommissioning, and information from currently operating nuclear power facilities. The staff's assessment includes an assessment of cumulative impacts. For discussions of cumulative impacts, the NRC used the terminology defined in 40 CFR 1508.7. "Cumulative impact is the impact on the environment, which results from the incremental impact of the action (in the case of this Supplement, that is decommissioning activities) when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time." The staff examined the cumulative impacts of decommissioning activities and other past, present, and reasonably foreseeable future activities at the licensed sites.

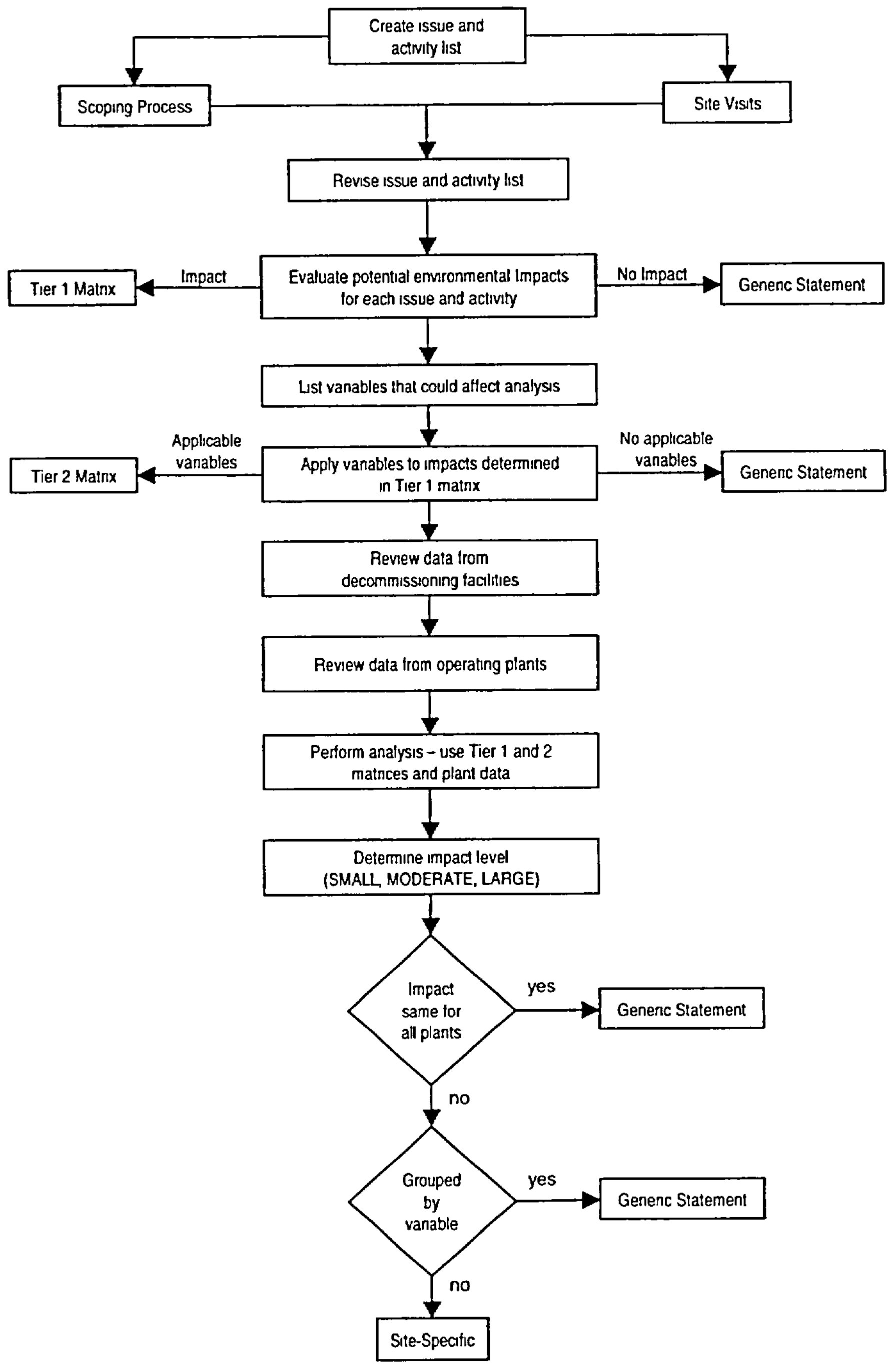

Figure 4-1. Environmental Impact Evaluation Process

Previous or anticipated decommissioning activities at the fast breeder reactor (FBR) or high-temperature gas-cooled reactor (HTGR) have not and are not expected to result in impacts that are different from those found at other nuclear reactor facilities.

After analyzing each issue, the staff determined the nature of the impact (site-specific or generic) and the significance level of the environmental impact (SMALL, MODERATE, or LARGE). This evaluation resulted in a range of impacts for each issue that may be used for comparison by licensees that are or will be decommissioning their facilities.

4.3 Environmental Impacts from Nuclear Power Facility Decommissioning

The following sections are organized by issue and discuss environmental impacts. Each section has four parts:

(1) Regulations – Identifies statutes, regulations, or limits relevant to the issue.

(2) Potential impacts from decommissioning activities - Discusses possible impacts related to the issue and defines, where appropriate, the terms detectable and destabilizing for the issue.

(3) Evaluation – Describes analysis and professional judgement used to estimate whether an activity or group of activities is likely to make a noticeable impact on the environment, considering the available data. If an impact is likely, existing and additional mitigation measures that can be taken to avoid the impact are evaluated. If an impact cannot be avoided, a determination is made as to whether the impact is likely to destabilize the resource.

(4) Conclusion – Provides the staff's conclusion on significance (SMALL, MODERATE, LARGE) and applicability (generic or site-specific) of impacts to the issue.

The conclusions from this chapter are summarized in two tables in Appendix H. Table H-1 provides a list of decommissioning activities that have been determined to have no environmental impacts. These activities can be performed by licensees without further analysis. Table H-2 provides a comprehensive summary of the decommissioning activities and associated environmental issues that have been determined by the staff to have potential environmental impacts. Providing they fall within the range of the impacts identified, these activities can be performed with no further analysis by the licensee.

4.3.1 Onsite/Offsite Land Use

Nuclear power facilities are large physical entities, of which 20 to 40 ha (50 to 100 ac) may actually be disturbed during plant construction. Other land commitments can amount to many thousands of hectares for transmission line rights-of-way (ROWs) and cooling lakes. Farming and other types of agricultural land use occur on some nuclear reactor facility sites. Some utilities have designated portions of their sites for land uses such as recreation, management of natural areas, and wildlife conservation.

4.3.1.1 Regulations

Nuclear power facilities that began initial operation after the promulgation of the National Environmental Policy Act of 1969 (NEPA; 42 USC 4321 to 4347) or the Endangered Species Act of 1973 (ESA; 16 USC 1531 to 1544) were sited and are operated in compliance with these statutes. Any modifications to the facilities after the effective dates of these acts and others (see Appendix L-2) must be in compliance with the requirements of these statutes. The ESA applies to both terrestrial and aquatic biota. The individual States may also have requirements regarding threatened and endangered species; the State-listed species may vary from those on the Federal lists. In addition, activities such as decommissioning must take into account and avoid disturbance of historic and archeological sites, and American Indian grave sites. (Native American Graves Protection and Repatriation Act of 1990; 25 USC 3001 et seq.)

4.3.1.2 Potential Impacts of Decommissioning Activities on Land Use

Temporary changes in onsite land use could occur at a nuclear reactor facility site during decommissioning. Temporary changes may include addition or expansion of staging and laydown areas or construction of temporary buildings and parking areas. These temporary changes in onsite land use do not change the fundamental purpose or use of the reactor site. The major activities that may influence onsite land use are removal of large components, such as the reactor vessel and steam generators, structure dismantlement, and low-level waste (LLW) packaging and storage. Table E-3 in Appendix E describes the activities that occur during decommissioning that influence offsite and onsite land use.

The need for land during decommissioning is affected by the site layout. Most sites have sufficient area existing within the previously disturbed area (whether during construction or operation of the site) and, therefore, no additional land needs to be disturbed. The major activities projected to occur for decommissioning that are expected to temporarily require land include activities such as staging of equipment and removal of large components. In addition, the large number of temporary workers needed to accomplish the major decommissioning

activities may require that temporary facilities be installed for onsite parking, training, site security access, office space, change areas, fabrication shops, mockups, and related needs.

Some activities, such as widening and rebuilding access roads or creating or expanding gravel pits for building roads, may occur offsite. The experience of plants that are being decommissioned has not included any needs for additional land offsite.

Changes to land use are considered detectable if changes in the area's general land-use pattern result. The change would be destabilizing if large-scale new development and major changes in the land-use pattern occur. For example, a new local access route through rural land to the plant would represent a detectable, but not destabilizing, change in many localities.

4.3.1.3 Evaluation

Nuclear power facility site areas range from 34 ha (84 ac) for the San Onofre Nuclear Generating Station in California to 9,700 ha (24,000 ac) for the Turkey Point Plant in Florida. According to NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (NRC 1996), of the operating reactors, 29 site areas range from 200 to 400 ha (500 to 1000 ac), with an additional 13 sites ranging from 400 to 800 ha (1000 to 2000 ac). Thus, almost 60 percent of the plant sites encompass 200 to 800 ha (500 to 2000 ac). Larger land-use areas are associated with plant cooling systems that include reservoirs, artificial lakes, and buffer areas.

The nuclear reactor facilities being decommissioned are predominantly on the smaller sites, primarily because the older, smaller reactors have already permanently ceased operation. Only 6 out of 21 sites (29 percent) were between 400 and 800 ha (100 to 2000 ac); 6 (29 percent) were larger than 800 ha (2000 ac); and the rest (43 percent) were smaller than 400 ha (1000 ac) (see also Appendix F).

Almost all of the sites undergoing active decommissioning are utilizing areas used during construction. Land requirements for decommissioning activities appear to be well within the range of land requirements for activities during major outages that occur in the course of normal operations. There does not appear to be any significant differences in land use between plants using SAFSTOR or DECON options. There is no experience with either ENTOMB option with commercial power reactors in the United States, although there is some entombment experience with former U.S. Department of Energy (DOE) scientific and nuclear materials production reactors. Because of the potential need for large amounts of concrete and aggregate for ENTOMB2, it is possible that a concrete batch plant might be set up onsite. There might not be adequate room within the operational area at some of the sites for such a

facility, but it is likely that the impact of such a disturbance would be temporary and minor. Smaller amounts of concrete and aggregate would likely be required for the ENTOMB1 option.

Many of the facilities currently being decommissioned are relatively small reactors and located on small areas of land. However, a comparison of the land-use needs shows that many activities require the same amount of land for reactors whether the reactor size is small or large. It does not appear that land use will be significantly greater for future decommissioning at remaining sites. Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in onsite or offsite land-use impacts that are different from those found at other nuclear reactor facilities. There has been limited experience with multi-unit sites. Multiple-plant sites that are being decommissioned may be able to economize on space by reusing laydown areas.

Large-component removal is similar in its land requirements to major component replacement activities, such as steam generator replacement and refurbishment activities. Based on previous experience with steam generator replacement at a pressurized water reactor (PWR), it was estimated in NUREG-1437 that ~1 to 4 ha (~2.5 to 10 ac) of land may be needed to accommodate laydown, staging, handling, temporary storage, personnel processing, mockup and training, and related needs (NRC 1996). The impacts of steam generator or other major component removal during decommissioning should be similar or less. Generally, this land has been previously disturbed during the construction of the facility. Once the major decommissioning activities are completed, this land could be returned to its previous uses.

Based on current information collected at sites using the DECON and SAFSTOR options, decommissioning activities that affect offsite land use are not expected unless major upgrades to transportation links are required. It may be necessary to establish or re-establish road, rail, or water transportation links into the site for the purpose of bringing in equipment (especially large equipment), removing large components, and shipping offsite certain chemicals, waste concrete and metal, or other materials created, contaminated, or used in the decontamination and dismantlement processes. In such cases, offsite land-use impacts may be detectable or destabilizing. Additional attention to transportation routing and to the organization of activities to minimize the need for transportation re-establishment or upgrade may be able to reduce the impacts to undetectable levels. The ENTOMB options may require additional land offsite for a concrete batch plant, but in most cases the land use for this activity will be temporary, though detectable.

4.3.1.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on land use, including comments received on the draft of Supplement 1 of NUREG-0586. For

facilities having only onsite land-use changes as a result of large component removal, structure dismantlement, and LLW packaging and storage, the impacts on land use are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that the potential impacts to land use onsite are SMALL. The staff has considered mitigation and concludes that no additional measures are likely to be sufficiently beneficial to be warranted.

If changes in land use beyond the site boundary are anticipated, the impacts may or may not be detectable or destabilizing, depending on the site-specific conditions, and cannot be predicted generically. Therefore, the staff has concluded that if new land uses beyond the site boundary are anticipated, the magnitude of the potential impact may be SMALL, MODERATE, or LARGE, depending on the nature, size, and permanence of the disturbance to existing land use and must be determined through a site-specific analysis.

4.3.2 Water Use

Nuclear reactor facilities are usually located near or adjacent to significant water bodies (aquifers, rivers, lakes, etc.) that are important to the region. Operating nuclear reactor facilities use water from multiple sources. For example, water from an adjacent lake might provide cooling water, whereas potable water may come from groundwater wells located onsite. Reactor cooling is the greatest use of water at an operating reactor. Other uses include waste treatment, potable water, process water, and site maintenance.

4.3.2.1 Regulations

Water use at nuclear reactor facilities is regulated by State- and locally-issued permits. Most States require permits for surface water or groundwater withdrawals.

4.3.2.2 Potential Impacts of Decommissioning Activities on Water Use

Cessation of plant operations will result in a significant decrease in water consumption because reactor cooling is no longer required. Although water will still be required for spent fuel cooling, this demand will decrease as the fuel ages. Dewatering systems may remain active during decommissioning of a nuclear facility to control the water pathway for the release of radioactive material. Table E-3 in Appendix E lists decommissioning activities that may influence water use. These activities include fuel removal, staffing changes, large component removal, decontamination and dismantlement (using high-pressure water sprays), structure dismantlement, and entombment.

Impacts to water resources of decommissioning activities would be considered detectable if such activities result in a significant change in water supply reliability. The reliability of water supplies is impacted by a variety of factors, such as natural climatic variability and the reliability of the regional and local water-supply infrastructures. For example, an additional incremental drawdown attributable to a groundwater well at a decommissioning site may be measurable at an offsite well. However, this does not necessarily constitute a detectable change in the reliability of the water supply. It would be detectable if the offsite well is unable to withdraw its permitted volumes as a result of this increased drawdown. The impacts of decommissioning activities are considered destabilizing if they result in a permanent and/or significant loss of water supply reliability. For instance, heavy pumping of an aquifer that results in subsidence may cause a permanent loss of aquifer capacity. Another example of a destabilizing impact is a change in site drainage or stream-channel changes that would result in a detectable and significant change in the probability of flooding.

4.3.2.3 Evaluation

In general, the impact of nuclear reactor facilities on water resources dramatically decreases after plants cease operation. The flow through the condenser of an operating plant can range from 3 to 78 m^3/s (49,000 to 1,200,000 gpm) (NRC 1996), depending upon the size of plant. This operational demand for cooling and makeup water is largely eliminated after the facility permanently ceases operation. As the plant staff decreases, the demand for potable water also generally decreases. However, in a few cases staffing levels have temporarily increased above levels that were common for routine operations. For these short periods of time, commonly during the early stages of decontamination and dismantlement activities, there may be a slight increase in demand for potable water.

Most of the impacts to water resources likely to occur during decommissioning of a nuclear facility are also typical of the impacts that would occur during decommissioning or construction of any large industrial facility. For example, providing water for dust abatement is a concern for any large construction project, as is potable water usage. However, the quantities of water required are trivial compared to the quantity used during operations. There are some activities affecting water resources and decommissioning nuclear facilities that are different from other industrial non-nuclear activities. The demand for water for spent fuel maintenance (approximately 200 to 2000 L [50 to 500 gal.] of water per day, depending on the size and location of the pool) and wet decontamination methods (such as a full flush of the primary system or hydrolasing embedded piping in place), although not large, are unique to nuclear facilities. One facility reported using approximately 9500 to 11,000 L (2500 to 3000 gal.) of water per day for spent fuel pool spray-cooling during the summer months. Additionally, water in some of the systems or piping may continue to be used during decontamination and dismantlement to

provide shielding from radiation for workers who are dismantling structures, systems, and components (SSCs) in the vicinity. For example, 912,000 L (240,000 gal.) of water was used at one site to fill the reactor cavity in preparation for the segmentation of the reactor vessel.

Common engineering practices, such as water reuse, are used to limit water use impacts at most construction or industrial sites. However, use of some of these practices may be limited by radiological exposure considerations at decommissioning sites.

Water use at decommissioning nuclear reactor facilities is significantly smaller than water use during operation. The water use will be greater in facilities that are undergoing decontamination and dismantlement than those that are in the storage phase. During ENTOMB, water will be required as the concrete for entombment is mixed. Greater amounts of water will be needed for the ENTOMB2 option than for ENTOMB1. However, in both cases, this process would be of short duration and would not consume quantities of water in excess of those used in the construction of large buildings.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in water use impact that is different from those found at other nuclear reactor facilities.

4.3.2.4 Conclusions

The staff considered available information on the potential impacts of decommissioning on water use, including information received on the draft of Supplement 1 of NUREG-0586. This information indicates that the impacts of decommissioning on water use are neither detectable nor destabilizing. Therefore, the staff makes a generic conclusion that the potential impacts to water use are SMALL. The staff has considered mitigation and concludes that no additional measures are likely to be sufficiently beneficial to be warranted.

4.3.3 Water Quality

There are quality standards for drinking water, protection of aquatic and terrestrial habitats, and release of potential pollutants to surface and groundwater environs. Nuclear reactor facilities are usually located above aquifers or adjacent to important sources of water. Intended and accidental releases of potential pollutants may impact the quality of these waters. This section considers water quality impacts of nonradioactive material for both surface water and groundwater during the decommissioning process. Impacts from releases of radioactive material in liquid effluents are discussed in Section 4.3.8, "Radiological."

4.3.3.1 Regulations

Intentional releases of nonradioactive discharges to surface waters are regulated through the National Pollutant Discharge Elimination System (NPDES; Section 402 of the Federal Water Pollution Control Act, commonly referred to as the Clean Water Act [CWA] [33 USC 1251 to 1387]) to protect water quality. Congress has delegated the responsibility for NPDES implementation to the U.S. Environmental Protection Agency (EPA). When the EPA determines that State programs are equivalent to the Federal NPDES program, the NPDES permitting process is delegated to the State. Generally, discharge limits specified by the NPDES permit are revisited every 5 years. Ongoing monitoring programs may be required as part of an NPDES permit.

The Resource Conservation and Recovery Act of 1976 (RCRA; 42 USC 6901 et seq.) addresses the need to investigate and clean up contamination in the event of the release of nonradioactive hazardous material not covered within the limits of the NPDES permit. As with the NPDES permitting process, Congress has delegated the responsibility for RCRA implementation to the EPA. Because NPDES permits regulate only intentional discharges to surface water, any accidental releases of nonradioactive hazardous materials that may impair water quality (surface water or groundwater) are regulated through the RCRA process. RCRA requires responsible parties to clean up environmental contaminants regardless of the time of their release. The degree of investigation and subsequent corrective action necessary to protect human health and the environment vary significantly among facilities. When the EPA determines that State programs are equivalent to the Federal RCRA program, the corrective action program is delegated to the State.

Based on an October 1978 decision by the Atomic Safety and Licensing Board, (TVA 1978a, TVA 1978b), NRC authority does not extend to matters within the jurisdiction of the EPA. More specifically, the NRC authority is limited for those matters expressly assigned to the EPA by the Federal Water Pollution Control Act Amendments of 1972. This decision would also apply to decommissioning nuclear reactor facilities.

4.3.3.2 Potential Impacts of Decommissioning Activities on Water Quality

Table E-3 in Appendix E shows the activities during decommissioning that may affect water quality. These major activities include fuel removal, stabilization, decontamination and dismantlement, and structure dismantlement. Separate assessments of potential impacts were performed for surface water and groundwater. Surface waters are most likely to be impacted either by stormwater runoff or by releases of substances during decommissioning activities.

Because water quality and water supply are interdependent, changes in water quality must be considered simultaneously with changes in water supply. For example, reduced groundwater pumping may result in a rise in the water table, providing a new pathway for contaminants currently in the subsurface. Changes in the landscape (terrain and vegetation) during decommissioning can alter the hydrologic pattern of recharge and surface-water runoff. The convergence of surface water over unvegetated soils may result in accelerated erosion and the delivery of sediment to important downstream habitat.

Impacts to water quality of decommissioning activities would be considered detectable if such activities result in a significant change in water-supply reliability. For example, stormwater erosion at a facility undergoing decommissioning may result in a measurable increase in suspended sediment in an adjacent stream or disposal of concrete onsite could alter local water chemistry of the groundwater. However, this does not constitute a detectable change in the reliability of the water supply unless the incremental change in sediment concentration precludes permitted or environmental uses. The impacts of decommissioning activities would be considered to be destabilizing on water quality if they result in a permanent or significant loss of water-supply reliability. For instance, significant increases in erosion might result in a permanent loss of benthic habitat for certain fish species.

4.3.3.3 Evaluation

Both the decommissioning activities themselves and the order in which the activities are performed control the impacts to water quality. The same activities performed in a different order can have a significantly different impact on water quality. The time between activities may also be important in assessing impacts. Delaying activities during SAFSTOR may exacerbate water-quality issues. For example, the aging of structures may create new pathways for groundwater to enter contaminated subgrade structures. This would be less of an issue for entombment of a facility, where the plant's contaminated SSCs are encased in concrete and maintained as a solid structure isolated from the environment.

Stormwater runoff and erosion control are issues faced at many industrial sites, and it is expected that after application of common BMPs, any changes in surface-water quality will be nondetectable and nondestabilizing.

All commercial nuclear power facilities have NPDES permits that regulate intentional releases of hazardous materials. Historically, unintentional releases of hazardous substances have been an infrequent occurrence at decommissioning facilities. Because the focus of decommissioning is the ultimate cleanup of the facility, considerable attention is placed on minimizing spills. Except for a few substances such as hydrocarbons (diesel fuel), such hazardous spills are

localized, quickly detected, and relatively easy to remediate. Relevant regulations are listed in Appendix L. Some of the groundwater parameters measured in the license termination plan (LTP) might also be indicators of a heretofore undetected nonradiological subsurface plume. If such indications were observed, further characterization and corrective actions would be dictated by the relevant regulations discussed in Appendix L and permits, if appropriate.

Certain decommissioning activities or options may result in changes in local water chemistry. For example, if licensees dismantle structures by demolition and disposal of the concrete rubble on the site, then there is a potential that the hydration of concrete could cause an increase in alkalinity of groundwater. The pH of interstitial (pore) water very close to the concrete rubble would remain above 10.5 for several hundred thousand years (Krupa and Serne 1988). However, as the leachate migrates away from the demolition debris, it is reasonable to expect the leachate pH to be rapidly reduced (within meters) to natural conditions due to the large buffering capacity of soils. While the leachate's pH may not be a water-quality concern, such leachate may affect the transport properties of radioactive and nonradioactive chemicals (notably metals) in the subsurface although this transport would not be detectable offsite. Surface spreading of the demolition debris over large areas may provide adequate opportunity for soils to buffer the pH to background. Because the nonradiological impacts would be nondetectable, they are considered to be generic for all sites. However, concentrated disposal of demolition debris, either within or outside of existing below-grade structures, would require below-grade compliance with RCRA guidelines. The radiological aspects of onsite disposal of slightly contaminated material would require a site-specific analysis and would be addressed at the time the LTP is submitted.

Current or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in water-quality impacts that are different from those found at other nuclear reactor facilities.

4.3.3.4 Conclusions

The staff considered available information on the potential impacts of decommissioning on nonradioactive aspects of water quality for both surface water and groundwater, including comments received on the draft of Supplement 1 of NUREG-0586. This information indicates that for all facilities the impacts of decommissioning on water quality will be neither detectable nor destabilizing. Therefore, the staff makes a generic conclusion that for all facilities, the impacts on nonradioactive aspects of water quality are SMALL. The staff has considered mitigation and concludes that no additional measures are likely to be sufficiently beneficial to be warranted.

4.3.4 Air Quality

Decommissioning activities have the potential to adversely impact air quality. The activities may be direct, such as demolition of buildings, or indirect, such as transportation of decommissioning workers to and from the site. This section discusses the nonradiological impacts of decommissioning on air quality. Radiological impacts on air quality are addressed in Section 4.3.8, "Radiological."

4.3.4.1 Regulations

The purpose of the Clean Air Act (CAA) as amended (42 USC 7401 et seq.) is to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." Section 118 of the CAA, as amended, requires that each Federal agency, such as NRC, with jurisdiction over any property or facility that might result in the discharge of air pollutants, comply with "all Federal, state, interstate, and local requirements" with regard to the control and abatement of air pollution. Pursuant to the Act, the EPA established National Ambient Air Quality Standards to protect public health, with an adequate margin of safety, from known or anticipated adverse effects of regulated pollutants (42 USC 7409). Hazardous air pollutants and radionuclides are regulated separately (42 USC 7412).

EPA's regulations are found in Title 40 of the Code of Federal Regulations. The National Primary and Secondary Ambient Air Quality Standards are found in 40 CFR Part 50. The standards related to particulate matter (40 CFR 51.06 and 40 CFR 51.07) are particularly relevant to decommissioning activities. Other regulations that may cover decommissioning activities are found in 40 CFR Part 61, which deals with hazardous air pollutants such as asbestos, chlorofluorocarbons, and radionuclides; 40 CFR Part 81, which deals with designation of areas for air-quality planning purposes; and 40 CFR Part 82, which deals with protection of stratospheric ozone.

In addition, State and local agencies have developed and enforce a variety of air-quality regulations. These regulations require permits for emission sources, limit emission rates, and set maximum atmospheric concentrations for pollutants. Finally, different regulations apply to indoor air quality and worker safety.

4.3.4.2 Potential Impacts of Decommissioning Activities on Air Quality

Table E-3 in Appendix E shows activities that may have an effect on air quality. These include organizational changes, stabilization, storage preparation for SAFSTOR, decontamination and dismantlement, structural dismantlement, entombment, and transportation. The potentially adverse impacts identified include (1) degradation of air quality caused by emissions (e.g., NO_x, CO, and hydrocarbons) from internal combustion engines, (2) increased particle loading of the atmosphere caused by the movement of vehicles and equipment, demolition of structures, dismantlement of systems, and operation of concrete batch plants, and (3) alteration of other characteristics of the atmosphere (e.g., the ozone layer) by releases of gases used in plant systems (e.g., in fire suppression or refrigeration).

Air-quality impacts of emissions from internal combustion engines and changes in atmospheric particle loading can be assessed by comparison with standards set in air-quality regulations. These potential impacts are considered detectable if a decommissioning activity is likely to cause a measurable increase in the concentration of one or more regulated air pollutants that can be directly attributed to the activity. The impact is considered to be destabilizing if the impact is detectable and causes a change in the attainment status of the region. Air-quality impacts of the releases of other gases can be assessed by comparison with the magnitude of potential releases during decommissioning with the magnitude of releases of the same or similar gases from other sources.

4.3.4.3 Evaluation

Decommissioning activities that have the potential to have a nonradiological impact on air quality include:

- worker transportation to and from the site
- dismantling of systems and removing of equipment
- movement and open storage of material onsite
- demolition of buildings and structures
- shipment of material and debris to offsite locations, and
- operation of concrete batch plants.

These activities typically take place over a period of years from the time the facility ceases operation until the decommissioning is complete and the license is terminated. The magnitude and the timing of the potential impacts of each activity will vary from plant to plant, depending on the decommissioning options selected by the licensee and the status of facilities and structures at the time of license termination.

Worker transportation: Air-quality impacts of transportation of workers to and from the site are caused by emissions from the vehicles and by fugitive dust from traffic on paved and unpaved roads. Consequently, the impacts can be estimated directly from the size of the work force. Experience with decommissioning indicates that for most sites the onsite work force tends to decrease from the time that plants cease operation until decommissioning is complete. There are occasional increases during specific decontamination and dismantlement activities. However, the work force during decommissioning is smaller than the construction work force and the work force during refueling outages, and almost always smaller than the work force during facility operation.

Assuming that neither the mix of vehicles used for worker transportation nor the vehicle occupancy is different during decommissioning than during plant construction or operation, emissions from vehicles and fugitive dust associated with traffic is expected to decrease during the decommissioning period. These decreases are expected to improve air quality rather than degrade it. Consequently, the change in air quality associated with changes in worker transportation during decommissioning should not be detectable or destabilizing at any site.

Dismantling systems and removing equipment: Air-quality impacts of dismantling systems and removing equipment may be caused by the generation and release of particulate matter associated with the physical activities of dismantling and by the release of gases from the systems (for example, refrigeration systems and fire-protection systems).

The predominant potential effluent from system dismantling and removal of equipment will be particulate matter and fugitive dust. This material will generally be released in and remain within buildings and other structures because most decommissioning activities associated with dismantling systems and removing equipment will be conducted inside the containment, auxiliary, and fuel-handling buildings. These buildings have systems to minimize airborne contamination, such as whole-building air filtration. Filtration systems control the release of particulate matter to the environment. These systems, which are typically maintained and periodically operated during decommissioning, reduce the impact of airborne particulate material. Where filtration systems are not in place to control particulate releases, temporary systems can be established, as needed. Special air-ventilation pathways may be established before the start of a SAFSTOR period to ensure that air ventilates from the building through

high efficiency particulate air (HEPA) filters. It is unlikely that particulate matter released to the environment as a result of system dismantlement and equipment removal will be sufficient to be detectable offsite. Special precautions are required for worker protection where hazardous materials such as asbestos may become airborne, as discussed in Section 4.3.10, "Occupational Issues."

Various systems associated with reactors contain gases that are of environmental concern. For example, some gases used in refrigeration systems and fire-suppression systems have been identified as ozone-depleting compounds. Venting of these gases to the atmosphere is prohibited by law. Standard methods exist to purge systems with these gases and limit releases to the environment to insignificant quantities. Other fire suppression and refrigeration systems may contain greenhouse gases. The quantities of these gases at a nuclear plant are generally small in comparison with the quantities of greenhouse gases released hourly by a fossil-fuel combustion plant used for heating or power generation. The impacts of ozone-depleting and greenhouse gases are global rather than local. Therefore, it is unlikely that releases of ozone-depleting or greenhouse gases during decommissioning of any nuclear power plant will be detectable or destabilize the environment.

Movement and open storage of material onsite: Movement of equipment and open storage of materials onsite during decommissioning are similar to activities during construction or demolition of an industrial facility. The air-quality impacts of the movement of equipment and open storage of materials onsite are primarily associated with fugitive dust. Movement of equipment outside of the buildings may generate fugitive dust. Movement of equipment may also alter the size distribution of particles on the ground, making the particles more susceptible to suspension by the wind. Mitigation measures will be taken to minimize dust to comply with local air-quality regulations. Common mitigation measures include watering and other soil stabilization measures, such as spraying sealants on the area and seeding. Therefore, it is unlikely that the movement of equipment and open storage of materials will be detectable or destabilize regional air quality.

Demolition of buildings and structures: Once decontamination has been completed, the demolition of buildings and other structures at a nuclear power plant is similar to demolition of buildings and structures at industrial facilities. Demolition of buildings and major structures may cause a temporary increase in fugitive dust from the site. Fugitive dust from demolition of buildings and structures will involve large particles that will settle to the ground quickly. Demolition will generally be limited to a small number of short-duration events. Mitigation measures will be used to minimize dust. Therefore, it is unlikely that the fugitive dust from demolition of buildings and structures will be detectable or destabilize air quality.

If residual contamination is present at the time of demolition, then the demolition of buildings and structures must be conducted using techniques that keep releases of contaminated material within regulatory limits. For purposes of assessing radiological impacts, impacts are of small significance if doses and releases do not exceed limits established by the Commission's regulations.

<u>Shipment of material and debris to offsite locations</u>: Dismantled equipment, material, and debris from decommissioning are typically removed from the site as decommissioning progresses. The number of shipments required during the decommissioning period depends on the method of transportation and the decommissioning option chosen. Although the number of shipments may be relatively large, the decommissioning period extends over several years. As a result, the number of shipments per day is small. Current experience is that there is an average of less than one shipment per day of LLW from the plant (see Section 4.3.17, "Transportation"). Therefore, it is unlikely that the emissions from a shipment or a small number of shipments per day would be detectable or destabilize local or regional air quality at any nuclear power plant undergoing decommissioning.

<u>Operation of a concrete batch plant</u>: The ENTOMB options will require a large amount of concrete and aggregate. Unloading, movement, and dispensing of the materials that make concrete result in fugitive dust in the vicinity of concrete batch plants. Most of the dust is associated with unloading dry cement at the concrete batch plant and loading mixers or trucks. This dust tends to consist of large particles that settle out of the air quickly. As a result, dust associated with concrete batch plant operations is likely to be localized near the concrete batch plant. There will also be emissions from heavy equipment at concrete batch plants and vehicles used to transport concrete from the concrete batch plant to the entombment site. The likely impacts of these emissions will be smaller than those from dust.

There are a number of mitigation measures that can be used to control dust. Dust control measures commonly used at concrete batch plants include enclosure of dumping and unloading areas and conveyors, use of filters, and use of water sprays. There would be no significant difference between a concrete batch plant used in the ENTOMB option and a batch plant used for any other major construction activity. Therefore, the staff considers it unlikely that the environmental impacts of operation of a concrete batch plant for a plant undergoing entombment would be detectable or destabilize air quality.

In summary, the most likely impact of decommissioning on air quality is degradation of air quality by fugitive dust. Fugitive dust during decommissioning should be less than during plant construction because the size of the disturbed areas is smaller, the period of activity is shorter, and paved roadways may exist. Use of BMP, such as seeding and wetting, can be used to

minimize fugitive dust. During demolition activities, some particulate matter in the form of fugitive dust may be released into the atmosphere, but much of this fugitive dust consists of large particles that settle quickly. To date, licensees decommissioning nuclear reactor facilities have taken appropriate and reasonable control measures to minimize fugitive dust. No anticipated new methods of conducting decommissioning and no peculiarities of operating plant sites are anticipated to affect this pattern.

The selection of the decommissioning option (DECON, SAFSTOR, ENTOMB1, or ENTOMB2) is more likely to affect the timing of air-quality impacts than the magnitude of the impacts. Immediate decontamination and dismantlement of the facility (DECON) results in impacts earlier than the SAFSTOR option, in which most decommissioning activities are postponed to permit residual activity in the plant to decay. ENTOMB1 and ENTOMB2 may include the dismantlement of structures outside of containment and, thus, could result in air-quality impacts related to fugitive dust that would be the same as or greater than during DECON.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in air-quality impacts that are different from those found at other nuclear facilities.

4.3.4.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on air quality, including comments received on the draft of Supplement 1 of NUREG-0586. This information indicates that the impacts of decommissioning on air quality are neither detectable nor destabilizing. Therefore, the staff makes the generic conclusion that the impacts on air quality are SMALL. The staff has considered mitigation and concludes that current and commonly used measures are sufficient and no additional measures are likely to be sufficiently beneficial to be warranted.

4.3.5 Aquatic Ecology

Aquatic ecology issues incorporate all of the plants, animals, and species assemblages in the rivers, streams, oceans, estuaries, or any other aquatic environments near a nuclear power facility. Aquatic ecology also includes the interaction of those organisms with each other and the environment.

4.3.5.1 Regulations

Federal laws that are included within a NEPA evaluation of aquatic ecology issues include the CWA, the ESA of 1973, the Fish and Wildlife Coordination Act (16 USC 661 to 667c), and NEPA. Although some biota may be affected by a number of decommissioning activities, full consideration is usually reserved for the more important aquatic resources, which may be either individual species or habitat-level resources. Some activities, such as removal of in-stream or shoreline structures, may require permits from other agencies.

4.3.5.2 Potential Impacts of Decommissioning Activities on Aquatic Ecological Resources

Table E-3 in Appendix E identifies decontamination and dismantlement and structural dismantlement as activities that may affect aquatic ecology. Aquatic ecological resources may be impacted during the decommissioning process via either the direct or the indirect disturbance of plant or animal communities near the plant site. Direct impacts can result from activities such as the removal of shoreline or in-water structures (i.e., the intake or discharge facilities), the active dredging of a stream, river, or ocean bottom, or the filling of a stream or bay while indirect impacts may result from effects such as runoff. During decommissioning, aquatic environs at the plant site may be disturbed for the construction of support facilities, such as to build a dock for barges or to bridge a stream or aquatic area. Additionally, aquatic environs away from the plant site may be disturbed to upgrade or install new transportation systems (e.g., a new rail line to support large component removal) or to install or modify transmission lines. In most cases, aquatic disturbances will result in relatively short-term impacts and the aquatic environs will either recover naturally or impacts can be mitigated. Minor impacts to aquatic resources could result from sediment runoff generation due to ground disturbance and surface erosion and runoff. Impacts may occur if shoreline or in-water structures, such as the intake or discharge facilities and pipes, are removed. These impacts will typically be temporary and will not be detectable nor will they destabilize important attributes of the resource. It is important that shoreline or in-water structure removal is managed in a manner that does not result in the establishment of nonindigenous or noxious plants and animals to the exclusion of native species.

If decommissioning does not include removal of shoreline or in-water structures, very little aquatic habitat is expected to be disturbed during decommissioning. Thus, practically all aquatic habitat that was used during regular plant operations or, at a minimum, was not previously disturbed during construction of the site will not be impacted. If all activities are confined to the plant operational areas, impacts are expected to be minor and would primarily result from increased sediment from physical alterations of the site. If no disturbances occur

beyond the regular operational areas of the site, it is expected that the impact to aquatic resources will be nondetectable, nondestabilizing, and easily mitigated.

In some cases, the aquatic habitats that were originally disturbed during the construction of the site will continue to be of low habitat quality at the time of site decommissioning, even beyond the normal operations boundaries. However, important resources could either develop on the site or colonize the area disturbed by the construction. If a decommissioning activity results in the "removal" of species from an area (e.g., if a commercial or recreational fishery is no longer possible), this may be detectable. Reworking the ground surface during construction could alter the surface-drainage patterns such that wetlands on the original construction site may no longer support an aquatic community. If this is an important local or regional resource, it may be considered destabilizing.

4.3.5.3 Evaluation

The primary factors that must be considered in evaluating the potential for adverse impacts in areas previously disturbed by construction include the quantity of habitat to be disturbed, the length of time since initial disturbance, and the successional patterns of the aquatic communities (especially nuisance species). Most of the important aquatic ecological resources are not likely to occur on most plant sites. If they do occur, the decommissioning activities can probably be planned to avoid or minimize detectable and destabilizing effects.

Two decommissioning activities may result in impacts to the aquatic environment: removal of structures from the shoreline or in-water environment and removal of contaminated soil from the site (the latter applies only if the soil is in or near an aquatic environment).

Additionally, dredging and modification of barge loading facilities may result in impacts to aquatic ecological resources. Periodic permitted, maintenance dredging of the barge unloading facility is not expected to result in long term detectable or destabilizing impacts to the aquatic environment. Impacts to the aquatic resources would be within the bounds of the generic assessment. However, a significant expansion of the barge unloading facility necessary to accommodate, for example, a large shipping package such as a reactor vessel would require a site specific assessment. The environmental assessment may be performed by the U.S. Corps of Engineers as part of the review to permit the enlargement of the barge unloading facility.

In most cases, the aquatic environment required to support the decommissioning process is relatively small and is normally a very small portion of the overall plant site. Usually, the areas disturbed or utilized to support decommissioning are within the boundaries of the site operational areas and typically are immediately adjacent to the reactor, auxiliary, and control

buildings. Discharge permits to the aquatic environment for operation are almost always greater than planned or realized during decommissioning. In almost all cases examined, licensees expect to restrict activities to previously disturbed areas and operate within the limits of operational permits.

The potential for adverse impacts are likely to be nondetectable or nondestabilizing regardless of the decommissioning option selected. The activity most likely to result in impacts to aquatic environments is specific to removal of shoreline or in-water structures. The decision to conduct these activities would not be dependent on the decommissioning option. The only option where shoreline or in-water structure removal appears to be guaranteed is for those plants where return to a "Greenfield" is desired or required.

When there is a decommissioning activity outside the operational area, the significance of the potential impacts are more difficult to define and will depend on site-specific considerations. The primary factors that need to be considered include the total acreage of habitat to be disturbed, and the overall importance of the plant or animal species or communities to be disturbed. If important resources may be affected by the decommissioning activities, the impacts may be detectable and destabilizing.

Current or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in aquatic ecology impacts that are different from those found at other nuclear reactor facilities.

4.3.5.4 Conclusion

The staff has considered available information on the potential impacts of removing facility structures or contaminated soil from or near the aquatic environment on the aquatic ecological resources, including comments received on the draft of Supplement 1 of NUREG-0586. For facilities where disturbance of lands beyond the operational areas is not anticipated, the impacts on aquatic ecology are not detectable or destabilizing. The staff believes that activities within operational areas including the removal of shoreline or in-water structures, will have minimal impact on aquatic resources provided all applicable BMPs are employed and required permits are obtained. Therefore, the staff makes a generic conclusion that for such activities, the potential impacts to aquatic ecology are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

If disturbance beyond the operational areas is anticipated, the impacts may or may not be detectable or destabilizing, depending on site-specific conditions and cannot be predicted

generically. Therefore, the staff concludes that if disturbance beyond the operational areas is anticipated, the potential impacts may be SMALL, MODERATE, or LARGE, and must be determined through site-specific analysis.

4.3.6 Terrestrial Ecology

Terrestrial ecology considers all of the plants, animals, and species assemblages in the vicinity of the nuclear power facility as well as the interaction of those organisms with each other and the environment. Evaluations of impacts to terrestrial ecology are usually directed at important habitats and species, including plants and animals that are important to industry, recreational activities, the area ecosystems, and those protected by endangered species regulations and legislation. Federally listed threatened and endangered species, and designated critical habitat for such species, are addressed in a separate section of this Supplement (Section 4.3.7). There are also many species identified by State agencies as endangered or threatened, and potential impacts to such species should be evaluated and mitigated, as appropriate. Important habitat resources include (but are not limited to) wetlands, riparian areas, resting or nesting areas for large numbers of waterfowl, rookeries, communal roost sites, strutting or breeding grounds for gallinaceous birds, calving grounds, and areas containing rare plant communities. Some States have programs to formally designate priority or rare habitat community types.

4.3.6.1 Regulations

Federal statutes that are directly applicable in a NEPA evaluation of terrestrial ecology issues include the ESA of 1973, the Migratory Bird Treaty Act of 1918 (MBTA) (16 USC 703-712), and portions of other statutes, such as the wetlands provisions of the CWA (see Section 4.3.5.1, "Regulations").

The MBTA was initially enacted in 1918 to implement the 1916 Convention between the United States and Great Britain (for Canada) for the protection of migratory birds. Specifically, the Act established a Federal prohibition, unless otherwise regulated, to pursue, hunt, take, capture, or kill any bird included in the terms of the convention, or any part, nest, or egg of any such bird. The MBTA was amended in 1936 to include species included in a similar convention between the United States and Mexico, in 1974 to include species included in a convention between the United States and Japan, and in 1978 in a treaty between the United States and the Soviet Union. Executive Order 13186 (2001) further defined the responsibilities of Federal agencies, such as the NRC, to ensure the protection of migratory birds and to consider potential impacts to migratory birds during the preparation of NEPA documents.

4.3.6.2 Potential Impacts of Decommissioning Activities on Terrestrial Ecological Resources

Table E-3 in Appendix E identifies stabilization, large-component removal, structure dismantlement, and decontamination and dismantlement as activities that may affect terrestrial ecology. Terrestrial ecological resources may be impacted during the decommissioning process via direct or indirect disturbance of native plant or animal communities in the vicinity of the plant site. Direct impacts can result from activities such as the clearing of native vegetation or filling of a wetland. Indirect impacts may result from effects such as erosional runoff, dust, or noise. During decommissioning, land at the site may be disturbed for the construction of laydown yards, stockpiles, and support facilities. Additionally, land away from the plant site may be disturbed to upgrade or install new transportation or utility systems. For example, building a new rail line may be necessary to support large-component removal. Installing or altering existing transmission lines could also have an effect on the terrestrial environment. In most cases, land disturbances will result in relatively short-term impacts and the land will either recover naturally or will be landscaped appropriately for an alternative use after completion of decommissioning.

Minor impacts to terrestrial resources could result from dust generation due to ground disturbance and traffic, noise from dismantlement of facilities and heavy equipment traffic, surface erosion and runoff, and migratory bird collisions with crane booms or other construction equipment. Most of these minor, indirect impacts are temporary and will not be significant issues after the completion of decommissioning. The effects of such impacts can also be minimized using standard BMPs.

Impacts to terrestrial resources are considered to be detectable if they result in changes to local species populations or plant or animal communities beyond the typical levels of natural variability (i.e., normal year-to-year variations). The impacts are considered to be destabilizing if they result in the extirpation of important species or result in long-term changes in ecological functions (such as flow of energy), species richness, diversity, or proportion of invasive species.

4.3.6.3 Evaluation

At most commercial nuclear facilities, there is a relatively distinct operational area where most or all site activities occur (e.g., materials and equipment storage, parking, substation operation, facility service and maintenance, etc.). This operational area usually includes all areas within the protected area fence, the intake, discharge, cooling, and other associated structures, as well as adjacent paved, graveled, and maintained landscaped areas. The operational area may include the entire area disturbed during facility construction, but is often considerably smaller.

Terrestrial habitats disturbed during the construction of the site will often continue to be of low habitat quality during plant operation and decommissioning. However, sensitive habitats can develop on the site or rare species can colonize the area disturbed during construction. This is especially true if the site has been in SAFSTOR for several decades. For example, reworking the ground surface during construction may have altered the surface-drainage patterns such that wetlands develop on the original construction site. Trees could grow to the point where they become usable as roosting or nesting sites for eagles, osprey, or wading birds. These habitats may be inhabited by sensitive species at the time of decommissioning. Rare species have colonized portions of the site at several operating commercial nuclear power plants.

In most cases, the amount of land required to support the decommissioning process is relatively small and is a small portion of the overall plant site. Usually, the areas disturbed or utilized to support decommissioning are within the operational areas of the site and typically are within the protected area. Usually, there is sufficient room within the operational areas to function as temporary storage, laydown, and staging sites. In most cases, management, engineering, and administrative staff would have been assigned space in existing support or administration buildings. In some cases, the licensees have installed trailers or temporary buildings to house engineering and administrative staff or to otherwise support decommissioning. Most licensees expect to restrict decommissioning activities to highly disturbed operational areas but a few expect to use lands beyond the operational areas, as defined above. The licensees typically anticipate utilizing an area of between 0.4 ha (1 ac) to approximately 10.5 ha (26 ac) to support the decommissioning process. One facility (Big Rock Point) required a new transmission line ROW to provide electrical power to the plant site during decommissioning (this line will also provide power to the onsite independent spent fuel storage installation [ISFSI] after decommissioning is completed). However, construction of a new transmission line ROW is probably an unusual situation. It is expected that some sites will require the reconstruction or installation of new transportation links, such as railroad spurs, road upgrades, or barge slips. Activities conducted within the operational areas are not expected to have a detectable impact on important terrestrial resources. Activities conducted outside the operational areas may have detectable impacts, depending on the magnitude and type of activity and the resources potentially affected.

None of the decommissioning options have a greater likelihood of resulting in detectable or destabilizing impacts to terrestrial resources. The selection of the decommissioning option is more likely to affect the timing of the impact on ecological resources than it is the magnitude of the impacts. DECON may require slightly more land area to support a larger number of simultaneous activities. The ENTOMB2 option would probably have the least likelihood of adverse impacts onsite because some large components may be left in place, reducing the land requirements needed for large construction equipment, waste storage, and barge or rail loading

areas. However, impacts of ENTOMB2 could be larger if additional land disturbance is required to install a concrete batch plant and associated material stockpiles. The potential impacts of SAFSTOR may be smaller than DECON, depending on the time over which activities are performed. If decontamination and dismantlement occur slowly over many years (incremental DECON), the same storage and staging areas can be reused for sequential activities. If many activities are performed over a short time period at the end of the SAFSTOR period, the impacts may be as large as those for DECON. The activity of demolition of construction material should not have significant nonradiological impacts beyond other decommissioning activities except for potential short-term noise and dust effects.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in impacts on terrestrial ecology that are different from those found at other nuclear facilities.

4.3.6.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning activities on terrestrial resources, including comments received on the draft of Supplement 1 of NUREG-0586. For facilities where habitat disturbance is limited to operational areas, the impacts on terrestrial ecology are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that for such facilities the potential impacts to terrestrial ecology are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

If habitat disturbance beyond the operational areas is anticipated, the impacts may or may not be detectable or destabilizing, depending on site-specific conditions and cannot be predicted generically. Therefore, the staff concludes that if disturbance beyond the operational areas is anticipated, the potential impacts may be SMALL, MODERATE, or LARGE and must be determined through site-specific analysis.

4.3.7 Threatened and Endangered Species

Plants and animals protected under the ESA of 1973 may be present at or near all commercial nuclear power facilities (Sackschewsky 1997). At operating plants, the most common potential impacts to endangered aquatic species are effects related to the operation of the cooling water system via impingement, entrainment, or occasional temperature or chemical effects. Because the cooling system is not used at a plant undergoing decommissioning, it is anticipated that the potential impacts of decommissioning on threatened or endangered aquatic species will normally be no greater than and likely far less than the potential impacts of plant operations.

For terrestrial species that are threatened or endangered, the most common potential impacts for operating plants are from transmission ROW maintenance activities. Most transmission lines beyond the switchyard are expected to remain energized, even after a commercial nuclear power facility closes operation, and the ROW maintenance activities are expected to continue. Therefore, the potential impacts of decommissioning on terrestrial species will normally be no greater than the potential impacts of plant operations.

4.3.7.1 Regulations

The ESA is the Federal statute that is directly applicable in a NEPA evaluation of threatened and endangered species issues. The ESA is intended to protect plant and animal species that are threatened with extinction and to provide a means to conserve the ecosystems on which they rely. Under the ESA, the U.S. Fish and Wildlife Service (USFWS) is responsible for all terrestrial and freshwater organisms. Marine and anadromous fish species are the responsibility of the National Marine Fisheries Service (NMFS). The ESA prohibits the taking of listed species and the destruction of designated critical habitat for listed species. The term "take" means to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect or attempt to engage in such conduct (16 USC 1532). The ESA applies to Federal agencies as well as individuals. However, in general, the prohibitions against take in respect to listed plant species are only applicable to Federal agencies or to individuals on Federal lands.

Section 7 of the ESA provides a means for Federal agencies to consult with USFWS and NMFS concerning impacts to endangered species resulting from Federal actions. Although USFWS and NMFS are the administering agencies, it is the responsibility of the action agency to determine the potential impacts of a proposed action (including licensing actions) on endangered or threatened species via the preparation of a biological assessment. If the consultation process results in a determination that there may be adverse impacts to listed species, Section 10 of the ESA provides a means for permitted takes that are incidental to otherwise legal activities.

4.3.7.2 Potential Impacts of Decommissioning Activities on Threatened and Endangered Species

Table E-3 in Appendix E indicates that stabilization, large-component removal, structural dismantlement, and decontamination and dismantlement are activities that may affect threatened or endangered species. Such species may be impacted during the decommissioning process either through direct take (kill, maim, or unable to reproduce) or via disturbances of native plant or animal communities near the plant site that the species relies on for food or

shelter. Additionally, an extended period of SAFSTOR may allow the establishment of onsite populations of protected species that may be adversely affected by facility decontamination and dismantlement at the end of the storage period.

The greatest potential for impact to protected species is associated with physical alteration or dismantlement of the facilities, landscape, or aquatic environment. Impacts can result from activities such as the removal of near-shore or in-water structures (e.g., the intake or discharge facilities); the active dredging of a stream, river, or ocean bottom; the filling of a stream, bay, or wetland; or the clearing of native vegetation. Indirect impacts may result from runoff, sedimentation, dust generation, or noise disturbance. The aquatic environment at a plant site may be disturbed for the construction of support facilities to allow barges to dock or to bridge a stream or other aquatic area. Additionally, terrestrial and aquatic environments away from the plant site may be disturbed to upgrade or install new transportation or utility systems. For example, a new rail line may be necessary to support large component removal. Installing or altering transmission lines could also affect the terrestrial and aquatic environment. In most cases, disturbances will result in relatively short-term impacts and the environment and local populations will either recover naturally or impacts can be mitigated using standard BMPs. An important exception may occur if near-shore or in-water structure removal or land surface disturbances result in the establishment of nonindigenous or noxious plants and animals to the exclusion of threatened or endangered species.

Impacts to endangered or threatened species are considered detectable if there are changes (attributable to the facility) in the species behavior or in the local population size that are greater than normal year-to-year variation. Impacts would be considered destabilizing if they result in direct mortality or major behavior changes (such as abandonment of most suitable habitat areas in the plant vicinity) or if they otherwise jeopardize the local population.

4.3.7.3 Evaluation

Usually, very little land will be disturbed during decommissioning that was not used during regular plant operations or previously disturbed during construction of the facility. If all activities are confined to site operational areas (i.e., within protected area fences, intake, discharge, cooling, and other associated structures, and adjacent paved, graveled, and maintained landscaped areas), the impacts to terrestrial threatened or endangered species are expected to be minor and nondetectable. Any impacts that did occur would primarily result from increased noise and dust generation from physical alterations of the plant site and from increased truck

traffic to and from the site. If no disturbances occur beyond the operational areas of the site, it is expected that the impact to threatened or endangered terrestrial species will be relatively small, temporary, and mitigable. The impacts of activities beyond the operational areas would depend on the activity, the species potentially affected, and the mitigation options available.

Unless there are major structural changes in the aquatic environment, the potential for adverse impacts to aquatic threatened or endangered species is expected to be minimal and nondetectable. Impacts to aquatic threatened or endangered species resulting from runoff/ sedimentation or chemical inputs during decommissioning will be significantly less than the potential entrainment and impingement impacts that were present when the plant was operating because of the drastically reduced water use.

The different decommissioning options will probably not differ significantly in potential impacts to threatened or endangered species, except in those cases where the plant is held in SAFSTOR for extended periods. In those cases, there is a greater potential for rare species to colonize areas that may subsequently be disturbed during the decommissioning process.

The likelihood of impacts to threatened and endangered species is related to their presence or absence. This issue requires consultation with appropriate agencies to determine whether threatened or endangered species are present and whether they would be adversely affected. Consultation under Section 7 of the ESA must be initiated to determine if protected species are near the plant. If species are identified, an assessment of the potential impacts of decommissioning must be determined. Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in impacts on threatened and endangered species that are different from those found at other nuclear facilities.

4.3.7.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on threatened and endangered species, including comments received on the draft of Supplement 1 of NUREG-0586. Based on this information, the staff has considered that the adverse impacts and associated significance of the impacts must be determined on a site-specific basis.

The ESA imposes two basic requirements on the NRC. First, the ESA requires the NRC to ensure that any action authorized, funded, or carried out by NRC is not likely to jeopardize the continued existence of any endangered or threatened species, or to result in the destruction or impairment of any critical habitat for such species. Second, the NRC is required to consult with the Secretary of the Interior (for freshwater and terrestrial species through the USFWS) or the Secretary of Commerce (for marine and some anadromous fish through the NMFS) to

determine if any listed species may be affected by an action. This consultation may be formal or informal, depending on the nature of the action, the species potentially affected, and the level of impacts to those species.

Acknowledging the site- and species-specific nature of threatened and endangered species and the special obligations imposed on the NRC by the ESA, the staff has concluded that the potential impacts to threatened and endangered species may be SMALL, MODERATE, or LARGE, and is not a generic issue. Informal consultation will be initiated by the NRC staff with the appropriate service after the licensee announces permanent cessation of operations. It is expected that any formal or informal consultation will be completed prior to the licensee beginning major decommissioning activities, which can occur 90 days after the submission of the post-shutdown decommissioning activities report (PSDAR). At that time, it will be determined whether such species could be affected by decommissioning activities and whether formal consultation will be required to address the impacts. Each State should also be consulted about its own procedure for considering impacts to State-listed species.

4.3.8 Radiological

The NRC considers radiological doses to workers and members of the public when evaluating the potential consequences of decommissioning activities. Radioactive materials are present in the reactor and support facilities after operations cease and the fuel has been removed from the reactor core. Exposure to these radioactive materials during decommissioning may have consequences for workers. Members of the public may also potentially be exposed to radioactive materials that are released to the environment during the decommissioning process. All decommissioning activities were assessed to determine their potential for radiation exposures that may result in health effects to workers and the public. This section considers the impacts to workers and the public during decommissioning activities performed up to the time of the termination of the license. Any potential radiological impacts following license termination are not considered in this Supplement. Such impacts are covered by the *Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities*, NUREG-1496 (NRC 1997).

4.3.8.1 Regulations

Decommissioning reactors in the United States continue to be licensed by the NRC and must comply with NRC regulations and conditions specified in the license. The regulatory standards for radiation exposure to workers and members of the public are found in 10 CFR Part 20 (see detailed discussion in Appendix G). Title 10 CFR Part 20 requires that the sum of the external and internal doses (total effective dose equivalent, or TEDE) for a member of the public may

not exceed 1 mSv/yr (0.1 rem/yr). Compliance is demonstrated by measurement or calculation, to show (1) that the highest dose to an individual member of the public from sources under the licensee's control does not exceed the limit or (2) that the annual average concentrations of radioactive material released in gaseous and liquid effluents do not exceed the levels specified in 10 CFR Part 20, Appendix B, Table 2, at the unrestricted area boundary. In addition, the dose from external sources in an unrestricted area should not exceed 0.02 mSv (0.002 rem) in any given hour or 0.5 mSv (0.05 rem) in 1 yr. Occupational doses are limited to a maximum of 0.05 Sv (5 rem) TEDE per year, with separate limits for dose to various tissues and organs.

Potential radiological impacts following license termination are not covered in this Supplement. Specific radiological criteria for license termination were added as Subpart E of 10 CFR Part 20 in 1997, and the basis for public health and safety considerations is discussed in NUREG-1496 (NRC 1997). These criteria limit the dose to members of the public to 0.25 mSv/yr (25 mrem/yr) from all pathways following unrestricted release of a property. In cases where unrestricted release is not feasible, the licensee must provide for institutional controls that would limit the dose to members of the public to 0.25 mSv/yr (25 mrem/yr) during the control period and to 1 mSv/yr (100 mrem/yr) after the end of institutional controls. These criteria will largely determine the types and extent of activities undertaken during the decommissioning process to reduce the radionuclide inventory remaining onsite.

Power reactor licensees are required to meet the requirements in 10 CFR 50.36a for effluent releases after permanent cessation of operations. Licensees are also required to keep releases of radioactive materials to unrestricted areas at levels as low as reasonably achievable (ALARA).

In addition to NRC limits on effluent releases, nuclear power facility releases to the environment must comply with EPA standards in 40 CFR Part 190, "Environmental radiation protection standards for nuclear power operations." These standards specify limits on the annual dose equivalent from normal operations of uranium fuel-cycle facilities (except mining, waste disposal operations, transportation, and reuse of recovered special nuclear and by-product materials). Radon and its decay products are excluded from these standards.

The NRC has not established standards for radiological exposures to biota other than humans on the basis that limits established for the maximally exposed members of the public would provide adequate protection for other species. In contrast to the regulatory approach applied to human exposures, the fate of individual nonhuman organisms is of less concern than the maintenance of the endemic population (NCRP 1991). Because of the relatively lower

sensitivity of nonhuman species to radiation, and the lack of evidence that nonhuman populations or ecosystems would experience detrimental effects at radiation levels found in the environment around nuclear power facilities, these effects are not evaluated in detail for the purposes of this Supplement.

4.3.8.2 Potential Radiological Impacts of Decommissioning Activities

As indicated in Table E-3 in Appendix E, all decommissioning activities have potential radiological concerns. Radiological impacts during decommissioning include offsite dose to members of the public and occupational dose to the work force at the facility. For this Supplement, public and occupational radiation exposures from decommissioning activities have been evaluated on the basis of information derived from recent decommissioning experience. Effluent releases anticipated during decommissioning were estimated from experiences in recent decommissioning activities from both PWRs and boiling water reactors (BWRs).

Many activities that take place during decommissioning are generally similar to those that occur during normal operations and maintenance activities. Those activities include decontamination of piping and surfaces in order to reduce the dose to nearby workers. Removal of piping or other components, such as pumps and valves, and even large components, such as heat exchangers, is performed in operating facilities during maintenance outages. However, some of the activities, such as removal of the reactor vessel or demolition of facilities, would be unique to the decommissioning process. Those activities would have the potential to result in exposures to workers who are close to contaminated structures or components, and to provide pathways for release of radioactive materials to the environment that are not present during normal operation.

4.3.8.3 Evaluation

At the cessation of plant operations, there are areas of the plant structures where residual radiation exceeds the radiation standards for license termination set forth in 10 CFR Part 20, Subpart E. One of the goals of decommissioning is to reduce this residual radiation to levels that would permit license termination. Most of the decommissioning activities listed in Table E-3 in Appendix E have the potential for radiological impacts. The staff expects that all of the activities that have potential radiological impacts will be conducted following approved procedures to keep doses ALARA and well within regulatory limits. Radiological impacts are considered to be undetectable and nondestabilizing, in the NEPA sense, if doses remain within regulatory limits.

For this Supplement, information gained from experience in decommissioning facilities has been used to evaluate radiological dose to workers and members of the public. Occupational

doses, radionuclide emissions, and doses to members of the public during decommissioning were compared to those experienced during periods of routine operation at the same facilities or at similar facilities. They were also compared to estimates presented in the 1988 GEIS (NUREG-0586 [NRC 1988]). This comparison was intended to demonstrate that the radiological consequences actually experienced at facilities undergoing decommissioning were bounded either by the site's EIS for normal operations or by the 1988 GEIS. The data were also used to determine whether it was appropriate to update the estimates for these impacts as presented in the 1988 GEIS.

In estimating the health effects resulting from both offsite and occupational radiation exposures as a result of decommissioning of nuclear power facilities, the staff used the risk coefficients per unit dose recommended by the International Commission on Radiological Protection (ICRP) (1991) for stochastic health effects such as development of cancer or genetic effects. The coefficients consider the most recent radiobiological and epidemiological information available and are consistent with those used by the United Nations Scientific Committee on the Effects of Atomic Radiation. The coefficients used in this Supplement are the same as those published by ICRP (1991) in connection with a revision of its recommendations for public and occupational dose limits. Excess hereditary effects are listed separately because radiation-induced effects of this type have not been observed in any human population, as opposed to excess malignancies that have been identified among populations receiving instantaneous and near-uniform exposures in excess of 0.1 Sv (10 rem). Regulatory limits for radiation exposure to specific organs and tissues are set at levels that would prevent development of nonstochastic effects. Therefore, nonstochastic effects, such as development of radiation-induced cataracts, would not be expected in any individual whose exposure remains within the regulatory limits.

<u>Occupational Dose</u>: As part of the occupational dose analysis, data were collected for annual occupational doses, doses by activity, and total dose from decommissioning, when that information was available. Because many of the facilities that provided information have not completed the decommissioning process, the data included in this analysis is from both actual operating data and from projections for specific activities. Routine occupational doses as reported to the NRC were used to compare collective worker doses during normal operations to those experienced during decommissioning. Projections for specific activities were also used to determine which were the greatest contributors to the cumulative occupational doses over the entire decommissioning period.

The data used for this evaluation are presented in Appendix G. Average occupational doses during the 5 years of normal operations preceding shutdown ranged from about 1.5 to 5 person-Sv (150 to 500 person-rem) per year for each reactor. The average annual collective doses during the years following shutdown were generally lower, ranging from less than 0.1 to

1.8 person-Sv (10 to 180 person-rem), although specific years during the most active decommissioning period may have produced collective worker doses comparable to, or greater than, those typically experienced during normal operation. Average annual doses to individual workers are also generally lower during decommissioning than during normal operation.

Table 4-1 compares cumulative occupational dose estimates from the 1988 GEIS (NRC 1988) to estimates for plants that are currently in the decommissioning process. The types of activities included in these estimates may vary between plants. For example, some estimates include doses from transportation or from activities related to spent fuel management, which are not considered part of the decommissioning process, as defined in the scope of this document. In general, estimates for currently decommissioning plants fell within the range of estimates in the 1988 GEIS, and in some cases were substantially lower than the Supplement 1 estimates for the corresponding type of reactor and decommissioning option.

The estimated cumulative doses for the entire decommissioning process ranged from about 3.5 to 16 person-Sv (350 to 1600 person-rem) for the facilities that provided data. Estimated doses for the reference facilities discussed in the 1988 GEIS ranged from 3 to 19 person-Sv (300 to 1900 person-rem). Because the range of cumulative occupational doses reported by reactors undergoing decommissioning was similar to the range of estimates for reference plants presented in the 1988 GEIS, it was not considered necessary to update the estimates in the previous document at this time.

Activities that resulted in the largest doses during decommissioning included removal of large components, such as the reactor vessel and steam generators. Dismantling the internal structures within the containment building was the activity producing the largest overall doses. Transportation and management of spent fuel each accounted for less than 10 percent of the total. Appendix G provides a more in-depth review of the exposures recorded and anticipated for various activities.

One of the major decommissioning activities that is not performed during routine operation or refurbishment is removal of the reactor vessel. Industry experiences from this activity were reviewed to estimate worker exposure and the amount of radioactive material removed (see Appendix H). As each utility performed this major activity, experiences were shared within the industry and the lessons learned have been used to reduce collective dose to workers and improve the process. Collective worker dose at these sites ranged from 0.14 to 1.8 person-Sv (14 to 180 person-rem). The dismantlement of radioactive structures for the ENTOMB2 option would involve placement of contaminated SSCs in the reactor or containment building.

Facilities could use a demolition process for dismantlement of uncontaminated or slightly contaminated structures; there is a potential for this activity to occur during the dismantlement phases of SAFSTOR, DECON, or ENTOMB1 options. The demolition debris could be disposed of onsite if nonradiologically contaminated. If the debris is radiologically contaminated, it could be sent to a LLW site (except for the ENTOMB1 option, where it would be disposed of in the reactor or containment building structure). However, in cases where the remaining activity was low enough that the licensee could meet the criteria in 10 CFR Part 20, Subpart E, and other regulations, the demolition debris could potentially be disposed onsite for either the DECON or SAFSTOR options. This process has been termed "Rubblization" (see Section 1.3). Rubblization would require a site-specific analysis. The site-specific analysis would be conducted at the time the LTP is submitted for the site. Occupational doses during the activity of crushing the material would be similar to those for dismantlement of the facility in preparation for demolition and offsite disposal. The occupational doses would need to meet the regulatory standards in 10 CFR Part 20. Disposal of the radiologically contaminated demolition debris onsite would also have to meet the radiological criteria for license termination given in 10 CFR Part 20, Subpart E.

Occupational doses to individual workers during decommissioning activities are estimated to average approximately 5 percent of the regulatory dose limits in 10 CFR Part 20, and to be similar to, or lower than, the doses experienced by workers in operating facilities. The average increase in fatal individual cancer risk to a worker during decommissioning, about 8×10^{-5} per year of employment, is less than 2 percent of the lifetime accumulation of occupational risk of premature death of 4.8×10^{-3}. Because the ALARA program continues to reduce occupational doses, no additional mitigation program is warranted.

Public Dose: This section addresses the impacts on members of the public from radiation doses caused by decommissioning activities, including doses from effluents as well as from direct radiation. To determine the relative significance of the estimated public dose for decommissioning, the staff compared dose projections for decommissioning with the historical (baseline) doses experienced at PWRs and BWRs during normal operations. The dose estimates were based on reports evaluating effluent releases during decommissioning efforts and are shown in Appendix G. Levels of radionuclide emissions from facilities undergoing decommissioning decreased because the major sources generating emissions in gaseous and liquid effluents are absent in facilities that have been shut down. However, decommissioning facilities continued to report low levels of radionuclide emissions that resulted from the residual radioactive materials remaining in the facilities. The doses to members of the public from these emissions were also very low. Collective doses to members of the public within 80 km (50 mi) were lower than 0.01 person-Sv (1 person-rem) per year at all decommissioning facilities for

Table 4-1. Comparison of Occupational Dose Estimates from NUREG-0586 (NRC 1988) to those for Decommissioning Reactors

Reactor Type/ Decommissioning Option	1988 GEIS Estimates - Cumulative Occupational Dose, person-Sv (person-rem)	Range of Estimates for Decommissioning Plants - Cumulative Occupational Dose, person-Sv (person-rem)[(a)]
Boiling Water Reactors		
DECON	18.74 (1874)	7 - 16 (700 - 1600)
SAFSTOR	3.26 - 8.34 (326 - 834)	3.5 (350)
ENTOMB	15.43 - 16.72 (1543 - 1672)	—
Pressurized Water Reactors		
DECON	12.15 (1215)	5.6 - 10 (560 - 1000)
SAFSTOR	3.08 - 6.694 (308 - 664)	4.8 - 11 (480 - 1100)[(b)]
ENTOMB	9.16 - 10.21 (916 - 1021)	—
Other Reactors (HTGR; FBR)	—[(c)]	4.3 (430)

(a) These data are based on information provided by plants that are undergoing or have completed the decommissioning process. For facilities that have been completely decommissioned, they represent actual doses accumulated during the decommissioning period For facilities that are still undergoing decommissioning, they represent a combination of actual doses accumulated during activities that have been completed and projected doses for future activities.

(b) The plant reporting a dose estimate of 1100 person-rem is designated as having elected the SAFSTOR option; however, the period between shutdown and active decommissioning was shorter than the minimum 10-year SAFSTOR period that was evaluated in the 1988 GEIS. Therefore, it may be more appropriate to compare the estimated dose for that facility to the 1988 GEIS estimates for the DECON option.

(c) The 1988 GEIS did not provide dose estimates for reactors other than reference light water reactors. Therefore, there are no previous estimates with which to compare the doses for decommissioning the HTGRs and FBR, which are somewhat unique in the commercial nuclear power industry. The dose estimates are expected to be consistent with PWRs and BWRs

which data were available, and, in most cases, they were comparable to or lower than the doses from operating facilities. Doses to a maximally exposed individual were less than 0.01 mSv/yr (1 mrem/yr) at both operating and decommissioning facilities, which is well within the regulatory standards in 10 CFR Part 20 and Part 50.

Offsite doses to the public attributable to decommissioning have been examined for both the maximally exposed individual and the collective doses to the population within 80 km (50 mi) of the plants. To date, effluents and doses during periods of major decommissioning have not differed substantially from those experienced during normal operation. Consequently, direct

exposure and effluents in gaseous and liquid discharges are not expected to result in maximum individual doses exceeding the design objectives of Appendix I to 10 CFR Part 50, the dose and effluent concentration limits in 10 CFR Part 20, or the limits established by EPA in 40 CFR Part 190. Both the average individual dose and the 80-km (50-mi) radius collective doses are expected to remain at least 1000 times lower than the dose from natural background radiation. It should also be noted that the estimated increased risk of fatal cancer to an average member of the public is much less than 1×10^{-6}. Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in occupational or public doses that are different from those found at other nuclear facilities.

4.3.8.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential radiological impacts of decommissioning. This information indicates that the radiological impacts of decommissioning will remain within regulatory limits. Therefore, the staff makes the generic conclusion that the radiological impacts of decommissioning activities are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

The staff also determined that the issue of the long-term radiological aspects of Rubblization or onsite disposal of slightly contaminated material could not be evaluated generically and would require a site-specific analysis. The site-specific analysis would be conducted at the time the LTP for the site is submitted.

4.3.9 Radiological Accidents

As indicated in the Introduction to this Supplement, the staff relies on the Waste Confidence Rule for determining the acceptability of environmental impacts from the storage and maintenance of fuel in the spent fuel pool. The Rule states, in part, that there is, "reasonable assurance that, if necessary, spent fuel generated in any reactor can be stored safely and without significant impact for at least 30 yrs beyond the licensed life for operation...of that reactor at its spent fuel storage basin" (54 FR 39767).[a] However, for the purpose of public information, the staff has elected to include a discussion of potential accidents related to the spent fuel pool in this Supplement.

(a) The Commission reaffirmed this finding of insignificant environmental impacts in 1999 (64 FR 68005). This finding is codified in the Commission's regulations in 10 CFR 51.23(a).

The likelihood of a large offsite radiological release that impacts public health and safety from a facility that has permanently ceased operation is considerably lower than the likelihood of a release from an operating reactor that impacts public health and safety. This is because the potential accidents associated with reactor operation are no longer relevant after the reactor fuel has been removed.

Radiological accidents considered in licensing nuclear power plants are classified as design basis accidents (DBAs) and severe (beyond design basis) accidents. DBAs are those accidents that both the licensee and the NRC staff evaluate to ensure that the plant can withstand normal and abnormal transients and a broad spectrum of postulated accidents without undue hazard to the health and safety of the public. Severe accidents are those that are beyond the design basis of the plant. They are more severe than DBAs because they may result in substantial damage to the fuel, whether or not there are serious offsite consequences. For the most part, DBAs focus on reactor operation and are not applicable to plants undergoing decommissioning. The only DBAs or severe accidents (beyond design basis) applicable to a decommissioning plant are those involving the spent fuel pool. These postulated accidents are not expected to occur during the life of the plant, but are evaluated to establish the design basis for the preventive and mitigative safety systems of the spent fuel storage facility.

4.3.9.1 Regulations

Regulations governing accidents that must be addressed by nuclear power facilities, both operating and shutdown, are found in 10 CFR Part 50 and 10 CFR Part 100. The environmental impacts of DBAs, including those associated with the spent fuel pool, are evaluated during the initial licensing process. The ability of the plant to withstand these accidents is demonstrated to be acceptable before issuance of the operating license. The results of these evaluations are found in license documentation, such as the staff's safety evaluation report, the final environmental statement (FES), and in the licensee's Final Safety Analysis Report (FSAR) or equivalent. The consequences for these events are evaluated for the hypothetical maximally exposed individual. The licensee is required to maintain the acceptable design and performance criteria throughout the life of the plant.

In addition, Appendix E to 10 CFR Part 50 requires each licensee to develop emergency plans and implementing procedures to protect health and safety in the event of an accident. These plans and procedures are maintained up to date during the period of operation of the plant and until such time afer the cessation of plant operations that the NRC grants relief from the emergency planning requirements.

4.3.9.2 Potential for Radiological Accidents as a Result of Decommissioning Activities

Table E-3 in Appendix E indicates that fuel removal, organizational changes, stabilization, chemical decontamination, large component removal, decontamination and dismantlement, system dismantlement, entombment, and transportation are activities that may lead to radiological accidents. Many activities that occur during decommissioning are similar to activities, such as decontamination and equipment removal that commonly take place during maintenance outages at operating plants. However, during decommissioning such activities may be more extensive than similar activities during the period of reactor operations. Consequently, potential accidents associated with these activities may have a higher probability during decommissioning than when the plant is operating. Accidents that occur during these activities may result in injury and local contamination; they are not likely to result in contamination offsite. This section addresses worker injuries from radiological accidents. Injuries from other causes are addressed in Section 4.3.10,"Occupational Issues."

Once the reactor fuel has been moved to the spent fuel pool, the only DBAs contained in the plant's FSAR that are applicable are those associated with the spent fuel pool. These accidents are generally related to fuel handling or dropping heavy objects into the spent fuel pool. As long as the integrity of the spent fuel pool and its supporting systems is maintained, the potential impacts of accidents are bounded by the impacts of those for the spent fuel pool DBAs.

After permanent shutdown of the reactor, the only severe accident of concern is one where the fuel in the spent fuel pool becomes uncovered and results in a zircaloy fire. In this regard, the staff recently conducted a study of spent fuel pool accident risk at decommissioning nuclear power facilities to support development of a risk-informed technical basis for reviewing exemption requests and a regulatory framework for integrated rulemaking (NRC 2001b). As part of its effort to develop generic, risk-informed requirements for decommissioning, the staff determined the frequency of beyond-design-basis spent fuel pool accidents. The event initiators included:

- seismic events (earthquakes)aircraft crashes
- aircraft crashes
- tornadoes and high winds

- impact of a dropped heavy load (such as a fuel cask), resulting in pool drainage or compression or buckling of stored assemblies.

Those spent fuel pool accident sequences that resulted in the spent fuel being uncovered were assumed to culminate in a zirconium fire. The consequences of a zirconium fire event are likely to be severe. The staff's study performed some bounding-consequences analyses.

The impacts of accidents where onsite and offsite doses remain below those allowable for the workers or the public are considered to be undetectable. Accidents that are likely to be undetectable include temporary loss of services, certain decontamination-related accidents, such as liquid spills or leaks during in situ decontamination, and, in some cases, the temporary loss of offsite power or compressed air. The impacts of accidents that could result in offsite doses that exceed EPA's protective action guides (PAGs) (EPA 1991) are considered to be destabilizing. The only accidents that are likely to have destabilizing impacts are those that involve pool drainage that leads to a zirconium fire.

4.3.9.3 Evaluation

The information in this section is based on reviews of existing information from licensees' documents analyzing accidents from decommissioning activities and from a technical review of spent fuel pool accident risk at decommissioning nuclear power facilities. The review of spent fuel pool accidents at decommissioning reactors was performed to support development of a risk-informed technical basis for reviewing emergency plan exemption requests and a regulatory framework for integrated rulemaking (NRC 2001b). Further detail on the sources of information that were used to develop the analysis is given in Appendix I. Because the sources of information included the FBR and the HTGR, the results given in this section are applicable for these facilities.

The accidents and malfunctions covered by licensing documents can be divided into five main categories:

- Fuel-related accidents: These include maintenance and storage of fuel in the spent fuel pool and the movement of fuel into the pool, which could result in fuel rod drops, heavy load drops, and loss of water.

- Other radiological- (nonfuel)-related accidents: These include onsite accidents related to decontamination or dismantlement activities (e.g., material-handling accidents or accidental cutting of contaminated piping) or storage activities (e.g., fires or ruptures of liquid waste tanks).

- External events: These include aircraft crashes, floods, tornadoes and extreme winds, earthquakes, volcanic activity, forest fires, lightening storms, freezing, and sabotage.

- Offsite events: These consist solely of transportation accidents that occur offsite (transportation accidents are discussed in Section 4.3.17).

- Hazardous (nonradiological) chemical-related accidents: These have the potential for injury to the offsite public, either directly from the accident or as a result of further actions initiated by the accident.

A detailed list of the types of accidents that could occur in each of these five categories is given in Appendix I. Appendix I also contains a table showing the estimated dose consequences of accidents during the decommissioning period that were reported in various licensing-basis documents. The highest doses result from postulated fuel-related accidents and radioactive-material-related accidents. Information obtained from licensing-basis documents for the fuel-related accidents showed that the highest offsite doses were from the cask or heavy load-handling accidents, the accidents that assumed a 100 percent fuel failure, and the spent fuel-handling accidents. The postulated accident with the greatest estimated offsite dose was a spent resin-handling accident that had a calculated offsite dose consequence accident of 0.0096 Sv (0.96-rem) TEDE.

The likelihood of an accident as well as its consequence are activity-dependent. Accidents related to dropping fuel elements occur only when the fuel is being moved. Accidents related to dismantlement activities would occur only during the decontamination and dismantlement process and not during a storage period or after a facility has been entombed. External events, however, could occur during any activity or decommissioning option. Table I-5 in Appendix I compares the types of accidents with the different activities that are performed during SAFSTOR, ENTOMB, and DECON.

The staff has reviewed activities associated with decommissioning and determined that many decommissioning activities not involving spent fuel that are likely to result in radiological accidents are similar to activities conducted during the period of reactor operations. The radiological releases from potential accidents associated with these activities may be detectable. However, work procedures are designed to minimize both the likelihood of an accident and the consequences of an accident, should one occur, and emergency plans and procedures will remain in place to protect health and safety while the possibility of significant radiological accidents exists.

In addition to the licensing-basis documents reviewed, the staff's report, *Technical Study of Spent Fuel Pool Accident Risk at Decommissioning Nuclear Power Plants* (NRC 2001b), provides an analysis of the consequences of the spent fuel pool accident risk and includes a limited analysis of the offsite consequences of a severe spent fuel pool accident. These analyses showed that the consequences of a spent fuel accident could be comparable to those for a severe reactor accident. As part of its effort to develop generic, risk-informed requirements for decommissioning, the staff performed analysis of the offsite radiological consequences of beyond-design-basis spent fuel pool accidents using fission product inventories at 30 and 90 days and 2, 5, and 10 years. The results of the study indicate that the risk at spent fuel pools is low and well within the Commission's Quantitative Health Objectives. The risk is low because of the very low likelihood of a zirconium fire even though the consequences from a zirconium fire could be serious.

The Commission has considered the storage of spent fuel and has concluded in the Waste Confidence Rule in 10 CFR 51.23 that "... spent fuel generated in any reactor can be stored safely and without significant environmental impacts for at least 30 years beyond the licensed life for operation...." The staff has reviewed the potential accidents associated with spent fuel storage during decommissioning, the likelihood of the accidents, and the potential consequences of the accidents. Emergency plans and procedures will remain in place to protect health and safety while the possibility of significant radiological accidents associated with spent fuel exists.

4.3.9.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, concerning the potential impacts of non-spent-fuel-related radiological accidents resulting from decommissioning. This information indicates, that with the mitigation procedures in place, the impacts of radiological accidents are neither detectable nor destabilizing. Therefore, the staff makes the generic conclusion that the impacts of non-spent-fuel-related radiological accidents are SMALL. The staff has considered mitigation and concludes that no additional measures are likely to be sufficiently beneficial to be warranted.

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential impacts of spent-fuel-related radiological accidents resulting from decommissioning. The staff affirms the conclusions in the Waste Confidence Rule and concludes that the impacts of spent fuel storage are SMALL. The staff concludes that additional mitigation measures are not likely to be sufficiently beneficial to be warranted.

4.3.10 Occupational Issues

Occupational issues are related to human heath and safety. The discussion here includes physical, chemical, ergonomic, and biological hazards. This discussion does not include radiological impacts, which are discussed in Section 4.3.8.

4.3.10.1 Regulations

The Occupational Safety and Health Act of 1970 (29 USC 651 et seq.) was enacted to safeguard the health of the worker. Regulations implementing the act are found in Title 29 ("Labor") of the Code of Federal Regulations, Subtitle B, "Regulations Relating to Labor." Subpart A of 29 CFR Part 1910 adopts, by reference, occupational safety and health standards which have been found to be national consensus standards or established Federal standards. Standards adopted in 29 CFR 1910.6 include, among others, standards of the American National Standards Institute, the American Society for Testing and Materials, the American Welding Society, the National Fire Protection Association, the National Institute for Occupational Safety and Health, the Society of Automotive Engineers, and Underwriters Laboratories. Specific safety and health regulations for Construction are included in 29 CFR Part 1926. These regulations are administered by the Occupational Safety and Health Administration (OSHA).

States may also develop and enforce State standards for occupational safety and health. However, State agencies may not assert jurisdiction over any occupational safety or health issue with respect to which a Federal standard has been issued under Section 6 of the Occupational Safety and Health Act unless the State has a plan for the development and enforcement of State standards. State plans for development and enforcement of State standards are covered by 29 CFR Part 1902. Approved State plans for enforcement of State standards are listed in 29 CFR Part 1952. These plans identify the State agency responsible for development and enforcement of the State standards.

4.3.10.2 Potential Impacts of Decommissioning Activities on Occupational Issues

Table E-3 in Appendix E indicates that nearly all decommissioning activities may impact occupational issues. Typical hazards of concern can be grouped into the following categories: physical, chemical, ergonomic, biological, and radiological (Plog 1988). Radiological hazards are discussed in Section 4.3.8, and other hazards are discussed in this section in the context of decommissioning activities.

The impacts of decommissioning activities on occupational issues are considered detectable if the accident or injury rate during decommissioning exceeds average U.S. industrial accident rates. The impacts of decommissioning activities on occupational issues are considered destabilizing if the accident or injury rate during decommissioning becomes sufficiently large that decommissioning activities must be halted to address worker safety and the decommissioning schedule is threatened.

4.3.10.3 Evaluation

Typically, any significant operation, such as decommissioning, will have an environment, safety and health (ES&H) plan that serves as the guidebook for anticipating and preventing any injury or harm occurring to the worker while working on that particular job. This plan addresses all the major occupational hazards and is used to ensure that OSHA, State, and other local standards are met. The site-specific ES&H plan for a decommissioning activity should be referred to for detailed information regarding specific worker health and safety information; the occupational hazards described in this Supplement should not be used for ensuring the protection of an individual worker health and safety.

Physical hazards: During the decommissioning process, the major sources of physical occupational hazards involve the operation and use of construction and transportation equipment. Vehicles, grinders, saws, pneumatic drills, compressors, and torches are some of the more common equipment that can cause injury if improperly used. Heavy loads, which are often moved about by cranes and loaders, must be controlled to avoid injury. The majority of these hazards will be part of dismantlement. Workplace designs and controls should be the first line of defense when preventing workplace injuries. Hard hats and other personal protective equipment (PPE) are also important interventions and can serve as a secondary protective measure should workplace controls fail.

Many activities during decommissioning, for example, the use of cutting torches, have the potential to initiate fires. These activities, which are common during construction and demolition, should be identified in advance. It is expected that precautions will be taken to minimize the likelihood of fires and that suitable measures will be available for dealing with fires should they occur.

Table 4-2. Predicted Noise Ranges from Significant Construction Equipment (EPA 1971)

Equipment	Levels in dBA at 15 m (50 ft)
Trucks	82-95
Front loader	73-86
Cranes (derrick)	86-89
Pneumatic impact equipment	83-88
Jackhammers	81-98
Pumps	68-72
Generators	71-83
Compressors	75-87
Back hoe	73-95
Tractor	77-98
Scraper/grader	80-93

Noise is also a physical hazard that will be significant during decommissioning. The majority of noise will come from equipment such as rivet busters, grinders, and fans. Table 4-2 lists the typical A-weighted sound levels (decibel [dBA] levels) of standard construction equipment without the use of noise control devices or other noise-reducing design features. Although workplace controls and designs are the best methods for reducing noise, PPE (e.g., earplugs) can also be used to protect against hearing loss. If workers need to use PPE, their ability to communicate effectively is reduced and safety may be compromised.

Temperature is a physical hazard that will vary, depending on the decommissioning location and the amount of indoor versus outdoor activity. Heat and cold stress should be considered in any decommissioning plans. Normal core temperatures are 37.6°C (99.6°F) or 37°C (98.6°F) as measured by mouth. Fluctuations in core temperatures of 1.1°C (2°F) below or 1.7°C (3°F) above the normal impair performance markedly. If this range is exceeded, health hazards, e.g., hypothermia or heatstroke, exist (Plog 1988).

Physical hazards are prevalent at all the decommissioning sites. The loudest dBA noise hazard at one plant was the fan noise of 107 dBA (see Section 4.3.16, "Noise"). One facility undergoing decommissioning provided information on the number of safety occurrences (minor and injuries), accident prevention notices, PPE violations, near misses, and OSHA reportables. Many PPE violations appear to be repeat offenders. Most of the injuries and incidents noted occur in the construction area. The maximum yearly number of incidents and injuries (37) appeared in 1998 with a high number of PPE violations (53) also occurring during this reporting year. Typically, no lost work time is attributed to injuries or incidents.

Electrical hazards are a significant concern during decommissioning. During stabilization, licensees often rewire the site to eliminate unneeded electrical circuits or repower certain operations from outside. For SAFSTOR, monitoring equipment may need to be installed and some systems will need to be de-energized. All of these activities, plus various other activities (operating cranes near power lines, digging near buried cables, etc.), pose electrical threats to workers. Proper precautions should be taken to avoid injury.

Chemical hazards: Inhalation and dermal contact with chemicals are serious worker health hazards. Ingestion is typically not a voluntary route of exposure but accidental ingestions (pipetting with mouth, siphoning gasoline, etc.) have been known to occur at the job site. Solvents and particulates are the two contaminants of greatest concern. Some of the key chemicals of concern found in building materials, paints, light bulbs, light fixtures, switches, electrical components, and high-voltage cables include asbestos, lead, polychlorobiphenyls (PCBs), and mercury. Other chemicals that have been found during decommissioning activities include low levels of potassium, sodium chromate, and nickel found in the suppression chamber. Also, quartz and cristobalite silica were detected during concrete demolition. Fumes, often including lead and arsenic, and smoke from flame cutting and welding are significant sources of chemical exposure during decommissioning.

Decommissioning involves many activities that expose workers to chemical hazards:

- chemical decontamination of the primary loop
- removal of reactor components
- decontamination of the piping walls
- removal of contaminated soil
- removal of radioactive structures

- removal of hydrocarbon fuel from storage
- removal of hazardous coatings
- removal of asbestos
- removal of chemical-containing systems, such as demineralizers and acid- and caustic-containing tanks
- removal of sodium and NaK residue.

Proper planning, workplace design, and engineering controls should be supplemented with PPE and appropriate administrative solutions to ensure adequate worker protection from not only chemical hazards but all hazards.

Chemical hazards at one facility undergoing decommissioning included lead and arsenic vapors, created from torch cutting and using the plasma arc, and quartz and cristobalite particulates, created from chipping and hammering. At the facility, air sample summary logs indicate a few exposures that exceeded OSHA's permissible exposure limit (PEL). Arsenic (PEL = 0.01 mg/m^3) levels exceeded the PEL four times during the sampling period. The highest arsenic reading was 0.03 mg/m^3 when using the torch and grinder to cut a hole during one activity. The same activity reported the only lead (PEL = 0.05 mg/m^3) reading above PEL at 1.5 mg/m^3. Quartz (PEL = 0.1 mg/m^3) and cristobalite (PEL = 0.05 mg/m^3) particulates greatly exceeded the PELs when using the chipping hammer (817.84 and 1.5 mg/m^3, respectively). The drill and chipping hammer also created too much quartz dust (9.2 mg/m^3).

Ergonomic hazards: The physiological and psychological demands of decommissioning work create ergonomic hazards in the workplace. Discomfort and fatigue are two indicators of ergonomic stress that can lead to decreased performance, decreased safety, and increased chance of injury (Plog 1988). The typical sources of ergonomic stress during decommissioning activities include mechanical vibrations, lifting, and static work. Workplace designs, work shifts, and breaks should be planned accordingly to avoid ergonomic stress.

Biological hazards: Biological hazards include any virus, bacteria, fungus, parasite, or living organism that can cause a disease in human beings (Plog 1988). Typical sanitation practices can help avoid the obvious vectors for disease. Having clean, potable drinking water, marking nonpotable water, and providing cleansing areas are the most important elements of a sanitation system.

Given that many nuclear reactor facilities undergoing decommissioning are old, there is an increased chance that workers will be exposed to molds and other biological organisms that grow in and on the buildings. Molds and fungus, when inhaled, can cause minor to serious pulmonary problems. Dermal contact could cause rash and/or irritation. A thorough inspection of the facility should be conducted and proper cleansing and PPE should be used when biological agents are identified.

In general, human health risks for most decommissioning options are expected to be dominated by occupational injuries to workers engaged in activities such as construction, maintenance, and excavation. Historically, actual injury and fatality rates at nuclear reactor facilities have been lower than the average U.S. industrial rates. Occupational injury and fatality risks are reduced by strict adherence to NRC and OSHA safety standards, practices, and procedures. Appropriate State and local statutes must also be considered when assessing the occupational hazards and health risks for any decommissioning activity. The staff assumes strict adherence to NRC, OSHA, and State safety standards, practices, and procedures during decommissioning.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in occupational hazard issues that are different from those found at other nuclear reactor facilities.

4.3.10.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential impacts of decommissioning activities on occupational issues. This information indicates that the impacts on occupational issues are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that for all plants, the potential impacts on occupational issues are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

4.3.11 Cost

A decommissioning cost assessment is not a NEPA requirement. However, an accurate decommissioning cost estimate is necessary for a safe and timely plant decommissioning. Therefore, this Supplement includes a decommissioning cost evaluation, but the cost is not evaluated using the environmental significance levels nor identified as a generic or site-specific issue.

4.3.11.1 Regulations

The regulatory procedure for decommissioning a nuclear power facility is set out principally in NRC regulations in 10 CFR 50.75, 50.82, 51.53, and 51.95. The regulations to ensure the safe and timely decommissioning of nuclear power facilities and the availability of decommissioning funds were originally established by the NRC in 1988. These regulations, principally 10 CFR 50.75, specify the minimum amount of funds that a LWR licensee must have to demonstrate reasonable assurance of sufficient funds for decommissioning. The minimum decommissioning funds required by the NRC reflect only the efforts necessary to achieve termination of the 10 CFR Part 50 license. Costs associated with other activities related to facility deactivation and site closure, including operation of the spent fuel storage pool, construction, operation, and decommissioning of an ISFSI, demolition of uncontaminated or decontaminated structures that meet release criteria, and site restoration activities after sufficient residual radioactivity has been removed to meet NRC license termination requirements are not included in the minimum decommissioning fund requirement.

The regulations in 10 CFR 50.75 also require that licensees submit, at least once every 2 years, a report on the status of its decommissioning fund, including specifying the amount of funds accumulated, and a schedule for accumulating the remainder to be collected. This report is to be submitted annually for plants that are within 5 years of the end of licensed operations. 10 CFR 50.75 (f)(i) also requires that each power reactor licensee shall report the status of its decommissioning trust fund annually if the facility has already closed (before the end of its licensed life).

In addition to the financial assurance requirements for decommissioning in 10 CFR 50.75, other requirements in 10 CFR 50.75 and 50.82 specify requirements for submitting cost estimates for decommissioning to the NRC:

- 10 CFR 50.75(f)(2) requires that a licensee shall, at or about 5 years prior to the projected end of operations, submit a preliminary decommissioning cost estimate.
- 10 CFR 50.82(a)(4)(i) requires a licensee to provide an estimate of expected costs for the activities being proposed in the PSDAR.
- 10 CFR 50 82(a)(8)(iii) requires a licensee to provide a site-specific decommissioning cost estimate within 2 years following permanent cessation of operations.
- 10 CFR 50.82(a)(9)(ii)(F) requires a licensee to provide an updated site-specific estimate of remaining decommissioning costs as part of its LTP.

The regulations in 10 CFR 50.82 also specify the criteria that a licensee must meet before they can withdraw funds from the decommissioning fund for decommissioning activities.

4.3.11.2 Potential Impacts of Decommissioning Activities on Cost

As indicated in Table E-3 in Appendix E, all aspects of decommissioning will have an impact on decommissioning costs. The potential impacts of decommissioning activities on cost vary due to the cost of waste management and disposal of the LLW generated during decommissioning and to the uncertainty associated with regulatory requirements.

The variability in waste management and disposal arises because the Barnwell Low-Level Radioactive Waste Management Disposal Facility, the last remaining facility that is available to dispose of all classifications of LLW generated by all but two nuclear power facilities located throughout the United States, is scheduled to stop accepting waste from all NRC licensees except those located in the Atlantic Compact by 2009 (see NUREG-1307, Rev. 9, *Report on Waste Burial Charges* [NRC 2000]). However, decommissioning of most of the nuclear power facilities in the United States is not expected to occur until sometime after 2009. This cost uncertainty is generally applicable to most of the nuclear power facilities that are currently being decommissioned and those that will be decommissioned in the future. This cost uncertainty, however, is somewhat mitigated by the availability of the Envirocare disposal facility in Utah. Envirocare can accept most Class A LLW for disposal from any generator in the United States. (More than 95 percent of LLW generated during nuclear power facility decommissioning is Class A.) Other LLW storage and disposal sites are also currently being proposed.

The uncertainty associated with regulatory requirements is a reflection of the different requirements and standards for cleanup applied by different States and localities. While NRC cleanup requirements for terminating a license are well defined, these other external requirements may significantly influence the cost of decommissioning. For example, local jurisdictions might impose additional requirements than those imposed by the NRC. The cost of the extra cleanup is not reflected in the decommissioning fund required by the NRC.

4.3.11.3 Evaluation

The estimated cost of decommissioning all of the nuclear power facilities that have been built and operated in the United States is provided in Table 4-3 (in January 2001 dollars). The costs provided in the table are those estimated by the owners of the individual plants and reported to the NRC.

Shown in the table are the actual costs to complete the decommissioning and terminate the 10 CFR Part 50 licenses for each of those facilities that have reached this milestone of their life-cycle. Facility-specific estimates are also provided for each plant that has been permanently shut down and is either actively undergoing decommissioning or is in safe storage awaiting active decontamination and dismantlement. The costs shown are estimates developed by the licensee and reported in their PSDARs, site-specific cost estimate reports, LTPs, etc. These estimates are adjusted to January 2001 dollars.

Table 4-3 provides the range of costs estimated by utilities to decommission all of the nuclear power facilities that are currently operating or have not indicated an intent to permanently shut down. Cost ranges, rather than facility-specific cost estimates, are provided for these plants, reflecting the fact that these estimates are not as well developed as for those plants that have already permanently shut down. These cost ranges were developed from licensee-provided estimates in the March 1999 biennial decommissioning reports adjusted to January 2001 dollars.

Finally, Table 4-3 provides a range of decommissioning cost estimates for the ENTOMB options. These options have not been used or considered by any U.S. nuclear power facility licensee to date. Cost estimation methods for the ENTOMB options are, thus, not as well developed as for the DECON and SAFSTOR methods. The values quoted in the table were developed from an analysis of the two entombment scenarios described in Chapter 3 for a "reference" (i.e., typical) PWR and BWR. The reference PWR was assumed to be the Trojan Plant in Oregon; the reference BWR was assumed to be the Columbia Generating Station in Washington.

The cost of decommissioning results in impacts on the price of electricity paid by ratepayers. These impacts generally occur over the life of the facility as the decommissioning fund is being collected. However, for those nuclear reactor facilities that shut down prematurely (as is the case for the majority of the facilities identified in Table 4-3), the impact may also occur for a number of years after permanent shutdown while the under-collected portion of the fund continues to be collected.

This analysis assesses the impact of cost by evaluating the total cost to decommission a nuclear power facility and terminate its Part 50 license. This impact is summarized in Table 4-4. As can be seen, the cost to decommission a large (>200 MWe) nuclear power facility is estimated to range from $150 million to $700 million and is highly dependent on the factors discussed previously.

4.3.11.4 Conclusions

The staff has reviewed these data, recognizing that an evaluation of decommissioning cost is not a NEPA requirement. This information is presented here as a summary of actual and predicted decommissioning costs based on recently available data.

4.3.12 Socioeconomics

There are two primary pathways through which nuclear power plant activities create socioeconomic impacts on the area surrounding the plant. The first is through expenditures in the local community by the plant work force, and direct purchases of goods and services required for plant activities. The second pathway for socioeconomic impact is through the effects on local government tax revenues and services. When a nuclear power plant is closed and decommissioned, most of the important socioeconomic impacts will be associated with the plant closure rather than with the decommissioning process.

4.3.12.1 Regulations

There are no Federal or State regulations pertaining to any particular level of socioeconomic impacts, as there are for some environmental effects. Socioeconomic impacts are an element of NEPA documentation that must be addressed and mitigated, if warranted.

4.3.12.2 Potential Impacts of Decommissioning Activities on Socioeconomics

As indicated in Table E-3 in Appendix E, all of the socioeconomic impacts of decommissioning are related to organizational or staffing changes. The impacts of decommissioning were assessed recognizing that the potentially large impacts of plant closure may occur simultaneously with those of the actual decommissioning activities. However, as indicated in Section 1.3, impacts related to the decision to permanently cease operations are outside the scope of this Supplement.

Socioeconomic changes related to direct expenditures in the local community are considered not detectable if there is little or no impact on housing values, education and other public services, and local government finances, are not distinguishable from normal background variation due to other causes. Impacts on housing are considered not detectable when no discernable change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and little or no housing construction or conversion

Table 4-3. Cost Impacts of Decommissioning (in January 2001 Dollars)

Nuclear Plant	Electric Power Generation Rating	Reactor Type	Decommissioning Option	Estimated Decommissioning Cost, $ million
Decommissioning Completed				
Fort St. Vrain	330 MWe	HTGR	DECON	230 (189 [1996])[a]
Pathfinder	59 MWe	BWR	SAFSTOR	20 (13 [1992])[a]
Shoreham	809 MWe	BWR	DECON	258 (182 [1994])[a]
Currently Being Decommissioned				
Big Rock Point	67 MWe	BWR	DECON	364
Dresden, Unit 1	200 MWe	BWR	SAFSTOR	340
Fermi, Unit 1	61MWe	FBR	SAFSTOR	36
GE-VBWR	13 MWe	BWR	SAFSTOR	10
Haddam Neck	619 MWe	PWR	DECON	404
Humboldt Bay, Unit 3	65 MWe	BWR	SAFSTOR	284
Indian Point, Unit 1	257 MWe	PWR	SAFSTOR	259
La Crosse	50 MWe	BWR	SAFSTOR	111
Maine Yankee	860 MWe	PWR	DECON	400
Millstone, Unit 1	660 MWe	BWR	SAFSTOR	563
Peach Bottom, Unit 1	40 MWe	HTGR	SAFSTOR	65
Rancho Seco	913 MWe	PWR	SAFSTOR	394
San Onofre, Unit 1	410 MWe	PWR	SAFSTOR	427
Saxton	NA	PWR	SAFSTOR	44
Three Mile Island, Unit 2	792 MWe	PWR	SAFSTOR	502
Trojan	1130 MWe	PWR	DECON	250
Yankee Rowe	167 MWe	PWR	DECON	244
Zion, Unit 1	1085 MWe	PWR	SAFSTOR	386
Zion, Unit 2	1085 MWe	PWR	SAFSTOR	495
Currently Operating				
69 PWR Reactors	486 - 1270 MWe	PWR	DECON/SAFSTOR	264 - 695
35 BWR Reactors	514 - 1265 MWe	BWR	DECON/SAFSTOR	152 - 663
"Reference PWR"	1130 MWe	PWR	ENTOMB1/ ENTOMB2	290 - 400
"Reference BWR"	1100 MWe	BWR	ENTOMB1/ ENTOMB2	410 - 750

(a) Actual cost to complete the decommissioning and the year the license was terminated.

Table 4-4. Summary of Cost Impacts by Decommissioning Option and Reactor Type and Size (January 2001 Dollars)

	Decommissioning Cost Range, $million					
Decommissioning Option	**PWR < 200 MWe**	**PWR ≥ 200 MWe**	**BWR < 200 MWe**	**BWR ≥ 200 MWe**	**HTGR**	**FBR**
DECON	244	250 - 404	364	>182[(a)]	189	--
SAFSTOR	44	259 - 597	13 - 284	340 - 563	65	36
DECON/SAFSTOR (currently operating reactors)	--	264 - 695	--	152 - 663	--	--
ENTOMB1/ENTOMB2	--	290 - 400	--	410 - 750	--	--

(a) Cost data from the Shoreham plant, which only generated one effective full power day. There was little or no contamination to many plant systems. Not representative of other large BWRs.

occurs. Detectable impacts result when there is a discernable increase or reduction in housing availability, rental rates and housing values exceed the inflation rate elsewhere in the State, or more than minor housing conversions and additions or abandonments occur. Destabilizing impacts occur when project-related demand results in a very large excess of housing or very limited housing availability, where there are considerable increases or decreases in rental rates and housing values, or when substantial conversion or abandonment of housing units occurs.

Socioeconomic changes related to tax revenues and services (education, transportation, public safety, social services, public utilities, and tourism and recreation) are considered not detectable if the existing infrastructure (facilities, programs, and staff) could accommodate changes in demand related to plant closure and decommissioning without a noticeable effect on the level of service. Detectable impacts arise when the changes in demand for service or use of the infrastructure is sizeable and would noticeably decrease the level of service or require additional resources to maintain the level of service. Destabilizing impacts would result when new local government programs, upgraded or new facilities, or substantial numbers of additional staff and unsupportable levels of resources are required because of facility-related demand.

4.3.12.3 Evaluation

The size of the work force varies considerably among operating U.S. nuclear power facilities, with the onsite staff generally consisting of 600 to 800 personnel per reactor unit. The average permanent staff size at a nuclear power facility ranges from 600 to 2400 people, depending on the number of operating reactors at the site. In rural or low-population communities, this number of permanent jobs can provide employment for a substantial portion of the local work

force. In addition to the work force needed for normal operations, many temporary personnel are required for various tasks that occur during outages. Between 200 and 900 additional workers may be employed during these outages to perform the normal outage maintenance work. These are work force personnel who may be in the local community only a short time, but during these periods of extensive maintenance activities, the additional personnel could have a substantial effect on the locality. If, as expected, the decommissioning process requires a smaller work force than the onsite operating staff (typically 100 to 200 staff) and if the local economy is stable or declining, the result of the reduction in work force related to plant closure could be economic hardships, including declining property values and business activity, and problems for local government as it adjusts to lower levels of tax revenues. However, even the small decommissioning work force will tend to mitigate temporarily the full adverse socioeconomic effects of terminating operations.

If there is a net reduction in the community work force but the economy is growing, the adverse impacts of this ongoing growth (e.g., housing shortages and school overcrowding) could be reduced.

If the decommissioning work force were substantially larger than the operating work force, the result could be increased demand for housing and public services but also increased tax revenues and higher real estate values. If the economy is characterized by decline, then decommissioning could temporarily reverse the adverse economic effects.

In a stable economy, a net increase in the community work force could lead to some shortages in housing and public services, as well as to the higher tax revenues and real estate values mentioned previously. In a growing economy, decommissioning could act as an exacerbating factor to the ongoing shortages that already might exist.

Changes in work force and population: Changes of over 3 percent to local population in a single year are expected to have detectable effects, while changes of over 5 percent are expected to result in destabilizing impacts. These negative impacts include reduction of school system enrollments, weakened housing markets, and loss of demand for goods and services provided by local businesses. The size of the work force required during decommissioning, relative to that during operations, is an important determinant of population growth or decline.

The impact from facility closure depends on the rate and amount of population change. If decommissioning begins shortly after shutdown with a large work force, then the impact of facility closure is mitigated. Facilities where layoffs are sudden and there is a long delay before active decommissioning begins are more likely to experience negative population-related socioeconomic impacts. Thus, large plants located in rural areas that permanently shut down early and choose the SAFSTOR option are the likeliest to have negative impacts. Considering all variables such as plant size and community size as the same, plants that go into immediate

DECON have less immediate negative impacts; the impacts from the ENTOMB option, assuming those preparations were made immediately after shutdown, would be less significant than those of SAFSTOR.

Data on changes in work force were collected at facilities that are being decommissioned where information on operational and decommissioning work force is available. This information is presented in Appendix J, Table J-1. The table also shows total population in the host county at the time of plant shutdown, to indicate the potential importance of the facility closure.

In order to identify any unusual downward trends in county population around the time of a facility shutdown, data were collected showing the range of percentage changes in population that have occurred at facilities currently being decommissioned. U.S. Census population data for the counties that house the decommissioning facility are used to assess changes in population around the time of shutdown by comparing percentage changes in the county population with State population changes during the same time period. This information is provided in Appendix J, Table J-2.

In only two cases did the corresponding county populations decline around the time of the closure (Indian Point, Unit 1, in Westchester, New York, and Millstone, Unit 1, in New London, Connecticut). However, during the same time period that the host counties experienced population declines, the hosting States also experienced population declines. This suggests that the decline in the county population was part of an overall State population trend. Observing population trends over a decade may not capture small population declines or reductions in the rate of growth from one year to the next; however, longer trends should indicate whether or not the county had any large destablizing population or housing impacts from the facility closure.

In 18 out of the 20 facility case studies where populations grew, the populations of the counties where the facilities are located increased more rapidly or at the same rate as the State population. The two cases where the populations of the counties grew at a slower rate include relatively rural counties in California (Humboldt and Alameda) during time periods when the State of California experienced very high urban population growth. In general, experience of decommissioning facilities to date does not show any impacts from population change, either because the closure-related changes were small relative to the population base or because they were offset by other growth in the area.

<u>Local tax revenues</u>: Changes in tax revenues of less than 10 percent are considered not detectable, i.e., they result in little or no change in local property tax rates and the provision of public services. Losses between 10 percent and 20 percent result in detectable impacts, with increased property tax levies (where State statutes permit) and decreased services by local municipalities. Changes over 20 percent have destabilizing impacts on the governments involved. Tax levies must usually be increased or services cut substantially, and the payment of debt for any substantial infrastructure improvements made in the past becomes problematic.

Borrowing costs for local jurisdictions may also increase because bond rate agencies downgrade their credit rating. However, it is important to remember that these rules of thumb are based on uncompensated changes. For example, if a local taxing jurisdiction lost a nuclear facility that amounted to 35 percent of its tax base, but 30 percentage points of this loss were made up by the opening of a new manufacturing facility, the net impact would be 5 percent or not detectable. Small, rural areas are more likely to be affected than more urban areas having a wider variety of economic opportunities and more sources of tax revenue. Impacts depend on the type of plant, size of plant, and whether or not there are multiple units at a site, all of which help determine the net loss in employment at plant closure as well as the loss of tax base.

More information is available for facilities that have recently closed than for facilities closed more than 10 years ago (see Appendix J, Table J-3). The findings from this body of evidence confirm the findings discussed above. The primary taxing authorities for most of the decommissioning plants are the county and city in which the facility is sited. Tax information is typically provided by local taxing authorities (assessor's office) or from town planners familiar with the tax revenues generated by the facility.

The tax revenue impacts on the local communities of facility closure range from zero impact (tax-exempt plants) to loss of 90 percent of the community tax base. The magnitude of tax-related impacts varies primarily by the size of the taxing jurisdiction and the taxing structure of the State in which the plant is sited, as well as certain plant characteristics. Hence, the smaller the taxing community (less economically diverse), the greater the tax revenue impact when the nuclear facility closes down.

In communities where the revenues from the facility made up over 50 percent of the tax revenue base (with the remaining tax revenues made up primarily of private residential real estate), there were significant increases in the tax rates on the remaining real estate as well as cut-backs in services provided by property-tax revenues. The manner in which a State calculates the value of the plant also affects both the amount and timing of tax losses when a nuclear power facility closes and how much such a closure disrupts the tax revenue stream in a given community:

- At one plant, the assessed value of the plant was calculated as a proportional share of the value of the parent corporation, where the percentage is based on the book value of assets in the State (or sub-State taxing jurisdiction) compared with the book value of the assets of the entire corporation. This approach kept the plant at full assessed value for 7 years after its permanent closure until it was dropped from the books of the parent corporation as an asset. Several other approaches are discussed in Appendix J.

- Tax rules may or may not permit gradual phase-out. In some cases, the taxable asset value of the plants was allowed to phase out over a period of time (3 to 5 years). In other cases, the plants were simply taken off the tax roles in 1 year.

- The State may or may not share the burden with local government. In one State, school districts' lost property-tax collections were offset by equalization methods at the State level, which reduced the impact due to plant closures. In another State, the small neighboring township was the sole recipient of all property-tax revenues generated by the plant. Thus, the community's tax revenues were significantly reduced when the revenue source shut down.

- Utility ratepayers in some jurisdictions are entitled to share in funds recovered from sale of plant components and commodities and unspent decommissioning funds. These are not taxes but are available to general fund revenues.

In addition to characteristics specific to the taxing jurisdiction, the size, age, and ownership of the facilities play a role in how much the facilities affect tax revenues. Generally, the larger the facility (MWt), the larger the tax revenue impact. In addition, aging of the facility depreciates its book value and its assessed value over time. Usually, the falling assessed value of an aging facility will have reduced the tax revenue of the facility before closure, thus lessening the change in tax revenues generated by the facility after closure. A facility that closes suddenly, well before the end of its license expiration, will have a greater impact on the community tax base. Finally, if a facility is owned by a public entity, there is no effect on the tax base from closure because the facility was never taxable.

The choice of the decommissioning option appears to have had no bearing on the loss of tax receipts. The impact has to do with the size and suddenness of the loss of tax revenue (size and age of facility) related to plant closure only. The length of delay between shutdown and decommissioning does not appear to affect the size of the impact on tax revenue losses. No commercial nuclear power reactor has used the ENTOMB options, but there is no reason to expect ENTOMB to have any different impact on tax revenue losses than SAFSTOR or DECON.

<u>Public services</u>: The impacts of decommissioning on public services are generally much smaller than the impacts of plant closure. Impacts of closure are closely related to the tax-related impacts on the community and are affected by the same characteristics of the plant (size and age, tax treatment, and dependence of the local community on plant-related revenues), but not on the choice of decommissioning option or the amount of time between shutdown and active decommissioning. Inquiries were made to local governments in the vicinity of closed plants about public service impacts during and after shutdown and decommissioning. Their assessments are discussed in Appendix J and data are shown in Table J-4. Analysis was also conducted in the course of preparing NUREG-1437 (NRC 1996). Based on that experience, the following generalizations can be made.

Detectable impacts on housing result when there is a discernable increase or reduction in housing availability, when rental rates and housing values exceed the inflation rate elsewhere in the State, or when minor housing conversions and additions or abandonments occur.

Destabilizing impacts occur when project-related demand results in a very large excess of housing or very limited housing availability, where there are considerable increases or decreases in rental rates and housing values, and when there is substantial conversion or abandonment of housing units. The prevailing belief of realtors and planners in communities surrounding the case study facilities is that closing the facilities has had a range of effects on the marketability or value of homes in the vicinity. Housing choices of local residents are rarely affected by the presence of the facility, but people may move into the area in response to (temporarily) softer housing prices and commute to a nearby urban area. However, the decommissioning process itself does not appear to have produced any detectable impacts on housing.

The impacts to the following public services may occur as a result of plant closure: education, transportation, public safety, social services, public utilities, and tourism and recreation.

In general, detectable impacts arise when the demand for service or use of the infrastructure is sizeable. Impacts would noticeably decrease the level of service or require additional resources to maintain the level of service. Destabilizing impacts would result when new programs, upgraded or new facilities, or substantial additional resources and staff are required because of facility-related demand. Specific information for each of the areas of public service for closed plants is provided in Appendix J.

In general, the communities that suffered the most from the tax-related impacts of plant closure also experienced the greatest impacts on public services. To some extent, the communities themselves control the amount of impact by how they allocate property taxes to local budgets before shutdown, and how they prioritize these services post-shutdown. For example, one community channeled a great deal of the surplus revenues into building extensive social services for the elderly and for local youth in its community. After the plant ceased operations, the tax revenues decreased, all of the social services were downsized, and many will have to be eliminated because they are not considered priority programs (relative to public safety and education). In a second case, the county provided relatively few social services. Thus, the impact on social services after the shutdown was minor, although several other categories of public service experienced larger impacts. For example, education was largely funded by plant tax revenues and the responsible school district has recently indicated that it may have to file for bankruptcy, so the impact there was substantial[a]. However, all of these impacts were related to plant closure; in no case did the decommissioning process itself result in detectable impacts on public services.

(a) The size of impact can be significantly influenced by the mechanism that the State uses for funding, e.g., if the State makes up the difference between what the local school districts can fund from the local property tax and what the State has decided is the appropriate level of per-student expenditures.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in impacts on socioeconomics that are different from those found at other nuclear facilities.

Summary: The impacts of plant closure are those that are observed by the community, rather than the impacts from decommissioning activities because they occur at about the same time. The impacts occur either through changing employment levels and local demands for housing and infrastructure, or through decline of the local tax base and the ability of local government entities to provide public services. The effects of employment changes on population growth are expected to be not detectable if population changes (reductions or increases) are less than 3 percent per year, detectable but not destabilizing if the population change is between 3 percent and 5 percent, and destabilizing if the population change is greater than 5 percent per year. Experience so far has shown that in most cases, reductions in employment related to plant closure even at fairly large sites do not generally produce local population changes greater than 3 percent, regardless of the type of plant and decommissioning option selected. The impacts of the decommissioning work force are even smaller.

The effect on the local tax base and public services related to closure depends on the size of the plant-related tax base relative to the overall tax base of local government, as well as on the rate at which the tax base is lost. Changes in annual tax revenues less than about 10 percent are considered nondetectable, i.e., they result in little or no change in local property tax rates and the provision of public services. Losses between 10 percent and 20 percent result in detectable but not destabilizing impacts, with increased property tax levies (where State statutes permit) and decreased services by local municipalities. Changes over 20 percent have destabilizing impacts on the governments involved. Experience has shown that publicly owned tax-exempt plants will not have an impact through this mechanism. In addition, fully depreciated plants, or a plant that is located in an urban or urbanizing area with a large or rapidly growing tax base will also not be impacted by this mechanism. A large, newer, relatively undepreciated plant, located in a small, isolated community, is much more likely to exceed the 20-percent criterion. If the plant tax base is phased out slowly after closure in these circumstances, the impact is more likely to be mitigated. Neither the type of reactor nor the method chosen for decommissioning matters.

Decommissioning itself has no impact on the tax base and no detectable impact on the demand for public services.

4.3.12.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential impacts of decommissioning on socioeconomics. This information indicates that the impacts of decommissioning on socioeconomics are neither detectable nor destabilizing. Therefore, the staff makes the generic conclusion that the impacts on socioeconomics are SMALL. The staff has considered mitigation and concludes

that no additional measures are likely to be sufficiently beneficial to be warranted.

4.3.13 Environmental Justice

An evaluation of environmental justice is performed to determine if minority and/or low-income groups bear a disproportionate share of negative environmental consequences. Executive Order 12898, dated February 16, 1994 (59 FR 7629), directs Federal executive agencies to consider environmental justice under NEPA. The Executive Order does not create whole new categories of impacts that need to be considered; nor does it create any right, benefit, or trust responsibility, substantive or procedural, that can be enforced by law or equity. It is designed to improve internal management of agencies to ensure that low-income and minority populations do not experience disproportionately high and adverse human health or environmental effects because of Federal actions.

Environmental justice has not been evaluated previously for decommissioning activities at reactor facilities.

4.3.13.1 Regulations

The CEQ has provided *Environmental Justice: Guidance Under the National Environmental Policy Act* (CEQ 1997). Although NRC is an independent agency, the Commission has committed to undertake environmental justice reviews, and has provided specific information in Office Instruction LIC-203, Nuclear Reactor Regulation (NRR), *Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues* (NRC 2001a). The CEQ guidance and NRR instructions provide several key definitions and the framework for analysis.

Low-income population: Low-income populations in an environmental impact area should be identified where census block groups within the environmental impact area have (1) more than 50 percent low-income persons or (2) the percentage of persons in households below the poverty level is significantly greater (typically, at least 20 percentage points) than in the geographical area chosen for comparative analysis. In identifying low-income populations, agencies may consider as a community either a group of individuals living in geographic proximity to one another or a set of individuals (e.g., migrant workers or American Indians[a]), where either type of group experiences common conditions of environmental exposure or effect.

Minority: Individuals who are members of the following population groups: American Indian and Alaska Native; Asian; Native Hawaiian and other Pacific Islander; Black or African

(a) For consistency, the term "American Indian" is used throughout this document to conform to the definition of "minority population."

American, not of Hispanic or Latino origin; or some other race and Hispanic or Latino (of any race).[a]

Minority population: According to the CEQ, minority populations should be identified where either (a) the minority population of the affected area exceeds 50 percent or (b) the minority population percentage of the affected area is meaningfully greater than the minority population percentage in the general population or other appropriate unit of geographic analysis. In identifying minority communities, agencies may consider as a community either a group of individuals living in geographic proximity to one another or a geographically dispersed/transient set of individuals (e.g., migrant workers or American Indians), where either type of group experiences common conditions of environmental exposure or effect. The selection of the appropriate unit of geographic analysis may be a governing body's jurisdiction, a neighborhood, census tract, or other similar unit that is to be chosen so as not to artificially dilute or inflate the affected minority population. A minority population also exists if there is more than one minority group present and the minority percentage, as calculated by aggregating all minority persons, meets one of the above-stated thresholds. NRR adopted a standard of 20 percentage points as "meaningfully greater."

Disproportionately high and adverse human health effects: When determining whether human health effects are disproportionately high and adverse, agencies are to consider the following three factors to the extent practicable: (a) whether the health effects, which may be measured in risks and rates, are significant (as used by NEPA), or above generally accepted norms (adverse health effects may include bodily impairment, infirmity, illness, or death); (b) whether the risk or rate of hazard exposure by a minority or low-income population, to an environmental hazard is significant (as used by NEPA) and appreciably exceeds or is likely to appreciably exceed the risk or rate to the general population or other appropriate comparison group; and (c) whether health effects occur in a minority or low-income population, affected by cumulative or multiple adverse exposures from environmental hazards.

Disproportionately high and adverse environmental effects: When determining whether environmental effects are disproportionately high and adverse, agencies are to consider the following three factors to the extent practicable: (a) whether there is or will be an impact on the natural or physical environment that significantly (as used by NEPA) and adversely affects a minority or low-income population (such effects may include ecological, cultural, human health, economic, or social impacts on minority communities, low-income communities, or American Indian tribes when those impacts are interrelated to impacts on the natural or physical environment); (b) whether environmental effects are significant (as used by NEPA) and are or may be having an adverse impact on minority populations, low-income populations, or

(a) "Other" may be considered a separate minority category. In addition, the 2000 Census included multi-racial data. Multi-racial individuals should be considered in a separate minority, in addition to the aggregate minority category.

American Indian tribes that appreciably exceeds or is likely to appreciably exceed those on the general population or other appropriate comparison group; and (c) whether the environmental effects occur or would occur in a minority or low-income population, affected by cumulative or multiple adverse exposures from environmental hazards.

4.3.13.2 Potential Impacts of Decommissioning Activities on Environmental Justice

As indicated in Table E-3 in Appendix E, decommissioning activities that may affect environmental justice are related to organizational or staffing changes and offsite transportation issues. However, the assessment of environmental justice is related to most of the other specific issues discussed throughout this Supplement. Any decommissioning activity that results in a disproportionate share of negative environmental consequences to minority or low-income groups has the potential to be an adverse environmental justice impact.

Detectability and destabilization, as they relate to environmental justice, must be defined in proportion to the minority and low-income populations that reside in the area of the power plant. Proportionment must be determined at each site at the time of decommissioning.

4.3.13.3 Evaluation

Most of the environmental justice impacts relate to land use, environmental and human health, and socioeconomics. Impacts due to onsite land disturbance are likely to be not detectable because the amounts of land disturbance are generally very small and usually occur in areas of the site previously disturbed by construction or operation of the facility. Impacts from disturbances to offsite land will generally not occur because offsite land generally is not disturbed as a result of decommissioning. If offsite land disturbance is required (e.g., if a new offsite road or rail spur is needed to transport large components or waste from decommissioning), the impact on environmental justice is site-specific because it will depend on the location of the new route relative to low-income populations or other affected resources on which they may depend. Some minority and low-income populations normally live along rail lines and truck routes. Previous transportation analyses have found that the impacts would be small from normal operations or from accidents. Thus, no disproportionately high and adverse effects are expected for any particular segment of the population, including minority and low-income populations, that may live along proposed rail and truck routes. Siting and construction of these offsite transportation upgrades would include an evaluation of cultural and other resources in the disturbed areas. Usually, offsite physical environmental impacts of decommissioning will be not be detectable because offsite environmental impacts from decommissioning are generally not detectable.

Socioeconomic impacts on minority and low-income populations due to plant closure could range from nondetectable to destabilizing, depending on the distribution of job impacts within the community and the effects of plant closure on local tax revenues and public services; however, the impact of decommissioning would generally not be detectable. More generic

information on overall socioeconomic impacts can be obtained by observing demographic statistics. In the 21 decommissioning case studies observed, it was concluded that facility closure would not have a detectable socioeconomic impact on low-income and minority populations. In other words, there appears to be no indication that minority or low-income populations would suffer disproportionately high and adverse impacts from the closure of the facilities. Because decommissioning has even smaller effects, its impact also would have been not detectable. The environmental justice conclusions are based on demographic information, i.e., the overall impact of the facility on the community. Discussions were also held with community members at some sites.

In addition, information provided by local government and social service providers helps determine the socioeconomic impacts on low-income and minority populations. In many of these case studies, the nuclear facilities are located in primarily white communities and tend to be located near bodies of water where upper-income real estate is built. Those that are employed by the facility tend to fall into the upper-income bracket within the communities where the facilities are located. Selected socioeconomic indicators are found in Appendix J, Table J-5, for the closed nuclear power plants studied.

The determination of whether the minority or low-income populations are disproportionately highly and adversely impacted by facility decommissioning activities needs to be made on a site-by-site basis because their presence and their socioeconomic circumstances will be site-specific. Data indicate there is no reason to expect adverse socioeconomic impacts to be correlated with type of plant (see Table J-5). However, adverse socioeconomic impacts are correlated with large facility size, early shutdown, and small, isolated host communities. If minority and low-income populations are present, adverse impacts from facility closure would be somewhat more likely in small, isolated communities than in larger urban areas. It is not clear whether these effects would be disproportionately high and adverse.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in environmental justice considerations that are different from those found at other nuclear facilities.

4.3.13.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on environmental justice, including comments received on the draft of Supplement 1 of NUREG-0586. Based on this information, the staff has concluded that the adverse impacts and associated significance of the impacts must be determined on a site-specific basis. Executive Order 12898 (59 FR 7629), dated February 16, 1994, directs Federal executive agencies to consider environmental justice under the National Environmental Policy Act 1969 (NEPA). Although the NRC is an independent agency, the Commission has committed to undertake environmental justice reviews. Subsequent to the submittal of the PSDAR, the NRC staff will consider the impacts related to environmental justice from decommissioning activities.

4.3.14 Cultural, Historic, and Archeological Resources

Cultural resources include any prehistoric or historic archeological site or historic property, site, or district listed in or eligible for inclusion in the National Register of Historic Places or otherwise having significant local importance. The Federal agency (in this case the NRC) is responsible for the evaluations through consultations with the State Historic Preservation Officer (SHPO), or if appropriate, the Tribal Historic Preservation Officer (THPO), that is responsible for determining which sites or properties are of significant historic or archeological importance. The NRC is also responsible for including other interested parties and affected American Indian tribes. Disagreements between the parties are resolved by the Advisory Council on Historic Preservation.

Evaluation of the potential presence of cultural resources should not rely solely on a query of the SHPO database, but should be based on field surveys and evaluations of the site. Although these evaluations may have been performed as part of the initial environmental evaluation for the sites or as part of another licensing action (e.g., license renewal), the coverage and adequacy of earlier survey efforts needs to be re-evaluated in cases where an impact may occur. Earlier field surveys and methods may not conform to current standards.

4.3.14.1 Regulations

The Federal statute that is most directly applicable to cultural resource issues during the decommissioning process is the National Historic Preservation Act (NHPA) of 1966 as amended (16 USC 470 et seq.). This Act created the National Register of Historic Places (National Register) and requires the heads of all Federal agencies to consider the impacts of the undertakings on any cultural properties that are listed on the National Register or that are eligible for listing. Section 106 of the NHPA requires each Federal agency to identify, evaluate, and determine the effects of an undertaking on any cultural resource site that may be within the area impacted by that undertaking. This section also requires consultation to resolve adverse effects of an undertaking and establishes mechanisms to obtain and incorporate comments from consulting parties. Federal agencies are directed by 36 CFR Part 800 to comply with the stipulations of NHPA as well as pertinent cultural, historical, and archeological protection provisions of NEPA, the Historic Sites Act of 1935, and the Antiquities Act of 1906 and their implementing regulations. The Historic Sites Act of 1935 (16 USC 461-467) declared a national policy of preserving for the public historic sites, buildings, and objects of national significance. It also led to the establishment of the Historic Sites Survey, the Historic American Buildings Survey, and the Historic American Engineering Record within the National Park Service.

Most other cultural, historical, and archeological protection regulations are primarily directed at resource protection on Federal lands, but in some cases these statutes may be applicable to the decommissioning of commercial power reactors. Several commercial nuclear power reactors are located on Federal lands. The Antiquities Act of 1906 (16 USC 431-433) prohibits destruction of vertebrate fossils and archeological sites on Federal lands and regulates their

removal under a permitting procedure. These regulations were further strengthened by the Archeological Resources Protection Act of 1979 (16 USC 470aa-47011), which prohibits the willful or knowing destruction and unauthorized collection of archeological sites and objects located on Federal lands. It also establishes a permitting system for archeological investigations and requires consultation with concerned tribes prior to permit issue. The Native American Graves Protection and Repatriation Act of 1990 (25 USC 3001 et seq.) protects graves on Federal lands and establishes tribal ownership of human remains and/or associated funerary objects taken from Federal lands and requires the inventory and repatriation to the tribes of any remains or funerary objects held by Federal agencies. Certain more recent Executive Orders regarding consultation with American Indian tribes and protection of religious sites and values could also be relevant.

Many of the States also have statutes that protect cultural, historical, and archeological resources on State lands. Some States also have burial and cemetery statutes that apply to private land as well. These State-level statutes are usually administered through the appropriate SHPO.

4.3.14.2 Potential Impacts of Decommissioning Activities on Cultural, Historic, and Archeological Resources

As indicated in Table E-3 in Appendix E, decommissioning activities that have a potential to adversely impact cultural resources include stabilization, decontamination and dismantlement, and large component removal. These activities adversely impact cultural resources primarily via land disturbance, which could damage or destroy the resource, or alter the contextual setting of the resource. In addition to the direct effects of land clearing, indirect effects such as erosion and siltation may adversely affect some cultural resources. Decommissioning activities also may alter the site access and administrative protection of the resources.

In a few situations, the nuclear facility itself could be potentially eligible for inclusion in the National Register of Historic Places, especially if it is older than 50 years and represents a significant historic or engineering achievement. In this case, appropriate mitigation would be developed in consultation with the SHPO. Even for buildings that are less than 50 years old, the processes and engineering that were employed may be of interest and may be eligible for the Historic American Engineering Record.

Impacts to cultural, historical, or archeological resources are considered detectable if the activity has a potential to have a discernable adverse affect on the resources. The impacts are destabilizing if the activity would degrade the resource to the point that it would be of significantly reduced value to the future generations, such as physically damaging structures or artifacts or destroying the physical context of the resource in its environment.

4.3.14.3 Evaluation

In most cases, the amount of land required to support the decommissioning process is relatively small and is a small portion of the overall plant site. Usually, the areas disturbed or utilized to support decommissioning are within the operational areas of the site and typically are within the protected area. Usually, there is sufficient room within the operational areas to function as temporary storage, laydown, and staging sites. In most cases, management, engineering, and administrative staff would be assigned space in existing support or administration buildings. In some cases, the licensees have installed trailers or temporary buildings to house engineering and administrative staff or to otherwise support decommissioning. In most cases examined, the licensees expect to restrict decommissioning activities to highly disturbed operational areas but a few do expect to use lands beyond the operational areas. The licensees typically anticipate utilizing an area of between 0.4 ha (1 ac) to approximately 10.5 ha (26 ac) to support the decommissioning process. One facility (Big Rock Point) required a new transmission line right of way (ROW) to provide electrical power to the plant site during decommissioning (this line will also provide power to the onsite independent spent fuel storage installation [ISFSI] after decommissioning is completed). However, construction of a new transmission line ROW is considered an unusual situation. It is expected that some sites will require the reconstruction or installation of new transportation links, such as railroad spurs, road upgrades, or barge slips. Activities conducted within the operational areas are not expected to have a detectable effect on important cultural resources because these areas have normally been highly degraded during facility construction and operation. Activities conducted outside of the operational areas may have detectable impacts, depending on the size and type of impact, and the cultural resources potentially affected.

The potential for adverse impacts is probably not affected by the type of facility (BWR, PWR, HGTR, or FBR) or the decommissioning option selected. However, the different decommissioning options are likely to alter the timing of the impact to cultural resources more than the magnitude of the impacts. DECON may require slightly more land area to support a larger number of activities occurring at the same time. ENTOMB2 would probably have the least likelihood of adverse impacts because some large components may be left in place, reducing the land requirements needed for large construction equipment, as well as waste storage and barge or rail loading areas. The potential impacts of SAFSTOR may be smaller than DECON or ENTOMB1, depending on the time period over which activities are performed. If dismantling and decontamination occur slowly over many years (incremental decontamination and dismantlement), the same storage and staging areas can be reused for sequential activities; however, if many activities are performed over a short time period at the end of the SAFSTOR period, the impacts may be as large as DECON.

4.3.14.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on cultural, historic, and archeological resources, including comments received on the draft of

Supplement 1 of NUREG-0586. For plants where the disturbance of lands beyond the operational areas is not anticipated, the impacts on cultural, historic, and archeological resources are not considered to be detectable or destabilizing. Therefore, the staff makes a generic conclusion that for such plants, the potential impacts to cultural, historic, and archeological resources are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

If disturbance beyond the operational areas is anticipated, the impacts may or may not be detectable or destabilizing, depending on site-specific conditions, and cannot be predicted generically. Therefore, the staff concludes that if disturbance beyond the operation areas is anticipated, the potential impacts may be SMALL, MODERATE, or LARGE and must be determined through site-specific analysis. Before the licensee conducts any decommissioning activity that might result in the disturbance of historic properties or archeological resources outside the site operational area, the NRC will, in accordance with the National Historic Preservation Act of 1966 as amended (16 USC 470 et seq.), consult with the appropriate SHPO or THPO to evaluate potential impacts.

4.3.15 Aesthetic Issues

Aesthetics is the study or theory of beauty and the psychological responses to it. Aesthetic resources include natural and man-made landscapes and the way the two are integrated. In this evaluation, aesthetic resources are considered to be primarily visual and relate the structures and the visual attributes of the decommissioning site.

4.3.15.1 Regulations

There are no regulations that relate specifically to the degree to which aesthetics may be impacted by a Federal project. The Bureau of Land Management (BLM), however, has developed a Visual Resource Management (VRM) system,[a] which involves cataloging scenic values, establishing management objectives for those values through the resource-management planning process, and evaluating proposed activities to determine whether they conform with the management objectives. This system provides tools for identifying the visual resources of an area and assigning them to inventory classes. It also provides tools for determining whether the potential visual impacts from proposed activities or developments meet the management objectives established for an area or whether design adjustments will be required. This tool was designed to meet the BLM's responsibilities for maintaining scenic values of public lands. However, it does not directly apply to a decommissioning facility, where the landscape has already been altered by the facility's structure.

(a) VRM System (http://www.blm.gov/nstc/VRM/vrmsys.html), accessed July 7, 2001.

4.3.15.2 Potential Impacts of Decommissioning Activities on Aesthetics

Table E-3 in Appendix E indicates that structure dismantlement and entombment are activities that may have aesthetic impacts. Nuclear power facilities generally contain four main buildings or structures, as described in Chapter 3: the containment or reactor building, the turbine building, auxiliary building, and cooling towers (if any). Cooling towers and stacks may be clearly visible from a distance. Sites also contain a number of storage tanks, a large switchyard, and various administrative and security buildings. Decommissioning may include demolition or dismantlement of any of these structures. The switchyard may be left in place after the termination of the license because it is an integral part of the power distribution grid.

Levels of impacts for aesthetic resources are defined largely by the impact of the proposed changes as perceived by the public, not merely the magnitude of the changes themselves. The potential for significance arises with the introduction (or continued presence) of an intrusion into an environmental context, resulting in measurable changes to the community (e.g., population declines, property value losses, increased political activism, tourism losses).

Decommissioning activities and the changes that they bring are considered to have a nondetectable impact on the host communities' aesthetic resources if there are (1) no complaints from the affected public about a changed sense of place or a diminution in the enjoyment of the physical environment and (2) no measurable impact on socioeconomic institutions and processes. They are considered to have detectable but not destablizing impacts on the host communities' aesthetic resources if there are (1) some complaints from the affected public about a changed sense of place or a diminution in the enjoyment of the physical environment and (2) measurable impacts that do not alter the continued functioning of socioeconomic institutions and processes. The activities are considered to have detectable and destabilizing impacts on the host community's aesthetic resources if there are (1) continuing and widely shared opposition to the activities or the changes the activities bring based solely on a perceived degradation of the area's sense of place or a diminution in the enjoyment of the physical environment and (2) measurable social impacts that perturb the continued functioning of community institutions and processes.

4.3.15.3 Evaluation

The aesthetic impacts of decommissioning fall into two sets: (a) impacts, such as noise, associated with decommissioning activities that are temporary and cease when decommissioning is complete and (b) the changed appearance of the site when decommissioning is complete.

Typically, nuclear power facilities are located in flat-to-rolling countryside in wooded or agricultural areas. In some cases, the facility structures are visible for many miles. In other cases, there are only a few views of the facility from the land, although it is more obvious from the water (lake, ocean, or bay).

Aesthetic issues related to construction and operation of facility structures were addressed in many (but not all) of the Final EISs prepared in response to applications for construction permits and operating licenses. In most cases, the visual impacts of the plant were said to have been mitigated to some extent by the surrounding topography or vegetation. In other cases, visible structures (such as cooling towers) were said to be "highly visible" but "the staff does not consider such an impact to be unacceptable." For decommissioning, the issue related to aesthetics is not one of placing another facility or building on a site, but one of removing buildings or structures.

The issues evaluated in this section concern the impacts of decommissioning activities on aesthetic resources at and around all types of nuclear power facilities (PWRs, BWRs, HTGR, or FBR). During the decommissioning period, the appearance of the facility will be slowly altered if the buildings are dismantled.

During decommissioning, the impact of activities on aesthetic resources would be temporary. The impacts would be limited both in terms of land disturbance and the duration of activity and would have characteristics similar to those encountered during industrial construction: dust and mud around the construction site, traffic and noise of trucks, and construction disarray on the site itself. In most cases, these impacts would not easily be visible offsite. Aesthetic impacts could improve fairly rapidly in the case of an immediate DECON if the licensee chooses to dismantle the facility, remove the structures, and regrade and revegetate the site before license termination. Impacts could also remain the same or similar in the case where the licensee maintains the structures throughout the decommissioning period and leaves them standing even after license termination (either after decontamination of the structures or possibly along with entombment of the reactor building) or throughout a long SAFSTOR period or ENTOMB. In these latter cases, the aesthetic impacts of the plant would be similar to those that occurred during the operational period.

The removal of structures is generally considered beneficial to the aesthetic impacts of the site. In a few cases, where facilities have been located on the Great Lakes or ocean coast, the facility may have been used by boaters as a landmark. However, it is highly unlikely that this would become an issue that would preclude dismantlement of the facility structures.

The retention of the structures during a SAFSTOR period or the retention of structures onsite at the time the license is terminated is likewise not an increased visual impact, but instead a continuation of the visual impact analyzed in the facility construction or operations FES. The staff has not identified any mechanism that would result in a greater negative aesthetic impact than had previously been considered during the development of the construction FES.

Decommissioning activities will be conducted onsite, both inside and outside existing buildings (in the case of dismantlement or shipping activities). Any visual intrusion (such as the

dismantlement of buildings or structures) would be temporary and would serve to reduce the aesthetic impact of the site. At a minimum, the aesthetic impact of the site would not be improved but would remain that of an industrial site as evaluated in the facility's original FES.

Licensees are expected to use best-management practices (BMPs) to control many of the potentially adverse impacts of decommissioning activities on aesthetics (e.g., dust and noise), as discussed in other sections.

4.3.15.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential impacts of decommissioning activities and the changes in plant appearance on aesthetics. This information indicates that the impacts on aesthetics are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that for all plants, the potential impacts on aesthetics are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

4.3.16 Noise

Noise is a "direct effect," as defined by Section 1508 of the CEQ Regulations for Implementing NEPA, i.e., effects caused by an action that occur at the same time and place as that action. For NRC licensees, the implementing regulations for NEPA are given in 10 CFR Part 51.

Noise is usually defined as sound that is undesirable because it interferes with speech, communication, or hearing; is intense enough to damage hearing, or is otherwise annoying. Noise levels often change with time. To compare levels over different time periods, several descriptors were developed that take into account this time-varying nature. These descriptors are used to assess and correlate the various effects of noise, including land-use compatibility, sleep and speech interference, annoyance, hearing loss, and startle effects:

- A-weighted sound levels (dBA) - typically used to account for the response of the human ear
- C-weighted scale (dBC) - generally used to measure impulsive noise such as air blasts from explosions, sonic booms, and gunfire
- day-night average sound level (DNL) - used to evaluate the total community noise environment. The DNL is the average A-weighted sound level during a 24-hour period with 10 dB added to nighttime levels (between 10 p.m. and 7 a.m) to account for the increased human sensitivity to night-time noise events.

The discussions in this section relate to noise and related impacts that may be heard offsite. The impacts from noise to workers is addressed in Section 4.3.10.

4.3.16.1 Regulations

The EPA was given the jurisdiction in the Noise Control Act of 1972 (42 USC 4901 et seq.) to promulgate and enforce the regulations that were issued under the Act. Funding for EPA to perform this function was eliminated in early 1981. However, Congress did not repeal the Noise Control Act. The DNL was endorsed by the EPA and is mandated by the U.S. Department of Housing and Urban Development (HUD), the Federal Aviation Administration (FAA), and the Department of Defense (DoD) for land-use assessments. The EPA has determined that no significant effects on public health and welfare occur for the most sensitive portion of the population (within an adequate margin of safety) if the prevailing DNL is less than 55 dB (NAS 1977). The FAA bases its noise guidelines on land use. For residential uses, sound levels up to 65 dB are acceptable. Certain residential areas with sound-blocking features can handle up to 75 dB. For livestock farming and breeding, compatibility is considered to exist up to 75 dBA. These guidelines are advisory in nature and are not mandatory (14 CFR Part 150).

The Federal Housing Administration (FHA), under HUD, established noise assessment guidelines under 24 CFR 51B (1979; amended April 25, 1996). The FHA/HUD site acceptability levels are summarized as follows:

- Acceptable (DNL is 65 dBA or less) - Typical building materials and construction will make any impacts to indoor noise minimal. Outdoor recreation and activities would not be impacted. No approval requirements or abatement measures are needed under this condition.

- Normally unacceptable (DNL is 65 to 75 dBA) - Noise exposure will impact outdoor use of the area and indoor use may be affected. Walls or other barriers may be needed to reduce outdoor noise levels. Indoor noise levels may need to be reduced using special construction methods.

- Unacceptable (DNL above 75 dBA) - The noise conditions in this situation are unacceptable and activities need to be approved on a case-by-case basis.

Local and State regulations may also exist regarding noise restrictions and abatement decisions. Many States prohibit only nuisance noise and have not established specific numerical environmental noise standards, while others have very specific requirements. For example, the State of Maine has sound-level limitations for construction that are a function of time of day, area characteristics, and duration of the noise.

4.3.16.2 Potential Impacts from Noise of Decommissioning Activities

Table E-3 in Appendix E indicates that structure dismantlement is an activity that may have noise impacts. During the decommissioning process, the sounds that might be heard at offsite locations include noise from construction, vehicles, grinders, saws, pneumatic drills, compressors, and loudspeakers. Noise levels from these sources have to be compared to current noise levels of the operating facility and background noise present at the site to determine potential impacts. Table 4-5 lists predicted noise ranges for significant sources of noise during decommissioning.

Noise level increases larger than 10 dBA to the DNL at the site boundary during the day might be expected to lead to interference with outdoor speech communication, particularly in rural areas or low-population areas where the day-night background noise level is in the range of 45 to 55 dBA.

The noise impacts of decommissioning activities are considered detectable if sound levels are sufficiently high to disrupt normal human activities on a regular basis. The noise impacts of decommissioning activities are considered destabilizing if sound levels are sufficiently high that the affected area is essentially unsuitable for normal human activities, or if the behavior or breeding of a threatened or endangered species is affected.

Table 4-5. Predicted Noise Ranges from Significant Decontamination and Dismantlement Sources (INEEL 1999)

			Predicted Noise Level Ranges (dBA) at Various Distances from the Reference Distance			
Source	**Source Strength dBA**	**Reference Distance, m**	**150 m (500 ft)**	**300 m (1000 ft)**	**0.8 km (0.5 mi)**	**1.6 km (1 mi)**
Construction Equipment	85-90	15[a]	65-75	59-69	51-61	45-55
Truck	85-90	15	65-75	59-69	51-61	45-55
Rail Engine	86-96	30[b]	76-86	71-81	64-74	58-68
Rail Car, 64 km/h (40 mph)	80-86	30	68-74	62-68	53-59	48-54

(a) 15 m ≈ 50 ft.
(b) 30 m ≈ 100 ft.

4.3.16.3 Evaluation

When noise levels are below those that result in hearing loss, impacts are judged primarily in terms of adverse public reactions to the noise. Generally, surveys around major sources of noise such as large highways and airports find that, when the DNL increases above 60 to 65 dBA, noise complaints increase significantly (FICN 1992). FHA/HUD uses a DNL of 65 dBA as the primary criterion for impact on residential properties and nearby populations. The staff believes that noise levels below 60 to 65 dBA are considered to be insignificant. Business and institutional properties may be less sensitive to changes in noise levels, but all populations of concern should be considered when estimating the noise impact of decommissioning activities.

Typically, operating reactor facilities do not result in offsite sound levels greater than 10 dBA above background. However, at some sites, sound levels at and above this level have been calculated at critical receptor locations. The principal sources of noise from facility operations are natural-draft and mechanical-draft cooling towers, transformers, and loudspeakers. Other occasional noise sources may include auxiliary equipment, such as pumps to supply cooling water from a remote reservoir. Generally, noise from these sources is not heard by a large number of people offsite. Of these sources, only loudspeakers would be anticipated to continue during the decommissioning period. The staff assumes that decommissioning activities will be scheduled to minimize high noise levels during the night and during critical periods for important animal species.

In most cases, during decommissioning the sources of noise would be sufficiently distant from critical receptors outside the plant boundaries that the noise would be attenuated to nearly ambient levels and would be scarcely noticeable, as in the case for operating plants. However, in some cases, such as the use of equipment to demolish concrete, the noise levels offsite could be sufficiently loud (60 to 65 dBA at the nearest receptor site) that activities may need to be curtailed during early morning and evening hours. It is highly unlikely, based on past decommissioning experience, that the offsite noise level from a plant during decommissioning would be sufficient to cause hearing loss. However, in one case, noises at a facility being decommissioned have been reported at levels of up to 107 dB (dropping to 50 dB less than 1.6 km [1 mi] away) as a result of the spent fuel pool cooling system. Nearby residents complained to the plant staff about these noise levels; engineering changes were made in the fans that were causing the noise and the issue was resolved.

The timing of the noise impacts and the duration or intensity will vary depending on the decommissioning option and the procedures that are used. More noise will occur during active dismantlement than during the storage period of SAFSTOR. Some demolition activities could increase noise levels temporarily. In addition to mitigation of noise levels based on engineering design, noise abatement procedures can be considered in decommissioning plans to reduce noise, particularly at night.

No differences are expected between the noise levels of future decommissioning activities at operating plants and the noise levels observed at facilities undergoing decommissioning. It is anticipated that most decommissioning activities will not represent an audible intrusion on the community for any type of nuclear power facility (BWR, PWR, HGTR, or FBR).

4.3.16.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential noise impacts of decommissioning activities. This information indicates that the noise impacts are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that for all facilities, the potential noise impacts are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

4.3.17 Transportation

In considering activities for decommissioning, transportation can be considered both an activity and an issue. Transportation of equipment, material, and waste is an activity that is performed throughout the entire decommissioning process. However, it is treated as an issue in this Supplement and is given its own section.

This section addresses impacts related to transporting equipment and materials (radiological and nonradiological) offsite. Materials transported to offsite disposal facilities include nonhazardous waste, LLW, hazardous waste, and mixed waste. As discussed in Chapter 1, the shipment of spent nuclear fuel is not within the scope of this Supplement. Radiological impacts include exposure of transport workers and the general public along transportation routes. Nonradiological impacts include additional traffic volume, additional wear and tear on roadways, and potential traffic accidents.

4.3.17.1 Regulations

Regulations that apply to the transportation of hazardous, mixed waste, and radioactive material promulgated by the U.S. Department of Transportation (DOT) are contained in 49 CFR Parts 171-177. NRC regulations related to transportation of LLW are contained in 10 CFR Part 71, "Packaging and transportation of radioactive material." These regulations contain requirements for transport vehicles, maximum radiation levels for packages and vehicles, special packaging requirements, driver training, vehicle and packaging inspections, marking and labeling of packages, placarding of vehicles, and training of emergency personnel to respond to mishaps. Highway routing restrictions for certain shipments of LLW are also included in DOT regulations. NRC regulations contain performance requirements for certain

types of transportation packages of radioactive material. In addition, Federal and State regulations govern the size and weights of trucks. The staff assumes that equipment, materials, and waste transportation are conducted within applicable regulations.

4.3.17.2 Potential Decommissioning Impacts from Transportation

Table E-3 in Appendix E indicates that transportation-related activities may impact the transportation infrastructure and public health and safety. The types of transportation impacts for decommissioning nuclear power facilities and operating plants are similar. The factors that determine the magnitude of transportation impacts of decommissioning include:

- changes in waste production due to decontamination and dismantlement activities that increase the amount of waste shipped offsite

- changes in the transportation methods (rail, truck, or barge) related either to the increased amount to be shipped offsite or to the type of material to be shipped.

- changes in the mix of types of waste categories shipped offsite.

The public health impacts result from exposures of transport workers and the general public along transportation routes during normal shipments and from material released as a result of transportation accidents, as well as from transportation accidents that do not involve the release of radioactive material. The radiological impacts to public health and safety are considered detectable if the dose rates from shipping containers exceed regulatory limits. They are considered destabilizing if material is shipped in unapproved containers. The nonradiological impacts of transportation of radioactive waste are considered detectable or destabilizing if the vehicles are maintained or driven in a manner that would result in a significantly greater accident rate than experienced by the trucking industry.

The nonradiological, infrastructure impacts are increases in traffic density, wear and tear on roadways and railways, and transportation accidents. The impacts of decommissioning activities on the transportation infrastructure are considered detectable if the increased traffic causes a decrease in level of service or measurable deterioration of affected roads that can be directly tied to activities at the plant. The impacts of decommissioning activities are considered destabilizing if the level of service becomes unacceptable or roads become unusable because of activities at the plant.

4.3.17.3 Evaluation

The transportation impacts are dependent on the number of shipments to and from the facility, the type of shipments, the distance that material is shipped, and the nonradiological waste/fixed waste quantities and disposal plans. The distance that the waste travels depends on the plant's proximity to a disposal site. One decommissioning facility, located in Oregon, ships LLW 480

km (300 mi) to the U.S. Ecology burial site on the Hanford Reservation in Richland, Washington. Another decommissioning facility located in California ships LLW 4300 km (2700 mi) to the Barnwell facility in South Carolina.

The number of shipments and volume of waste shipped during the decontamination and dismantlement phases of decommissioning are greater than during operations. Information on shipments, which was received from nine plants, is shown in Appendix K. Because data on the waste volume of shipments were received from only seven plants, estimates of waste volume and shipment numbers in several cases (as footnoted in the table) reflect only a single facility and may be significantly higher or lower than for the average facility in that grouping. The impacts from FBRs and HTGRs would be encompassed by those for the PWRs and BWRs since the distance shipped is less and the plant sizes are generally smaller.

Nonradioactive material from the site for general disposal will likely be shipped to landfills. However, because licensees cannot release material with detectable amounts of radioactive material, a number of sites may ship much of their solid waste to vendors specializing in the management of LLW or to LLW sites such as that at Clive, Utah.

A generic analysis was conducted to estimate human health impacts associated with transporting decontamination and dismantlement wastes from reactor sites to LLW burial grounds. The RADTRAN 4 computer code (Neushauser and Kanipe 1992), which is commonly used for transportation impact calculations in support of environmental documentation, was used for the analysis. RADTRAN 5 (Neushauser and Kanipe 1996) is the latest version of the code, originally developed by Sandia National Laboratories to support the NUREG-0170 environmental impact analysis (NRC 1977). It uses the same basic methods for calculating impacts but does the calculations in a probabilistic framework.

Based on information from Trojan and Maine Yankee, LLW was categorized as one of three types--high activity, low activity, and very low activity--and a typical volume and activity were estimated for each type of LLW. The impacts of transporting each type of LLW were estimated. There are likely to be additional nonradiological impacts on public health and safety from transportation accidents associated with transportation of uncontaminated material.

Radiological impacts: For this Supplement, the public health and safety impacts of transportation of radioactive waste are evaluated on the basis of compliance with applicable regulations. The Commission has taken the position (46 FR 21619) that its "...regulations are adequate to protect the public against unreasonable risk from the transportation of radioactive materials." This evaluation was based, in part, on the findings of NUREG-0170 (NRC 1977). A recent re-evaluation of transportation risks, using updated information and assessment tools (Sprung et al. 2000), found that risks are lower than estimated in NUREG-0170. Licensees are expected to comply with all applicable regulations when shipping radioactive waste from decommissioning. Therefore, the effects of transportation of radioactive waste on public health and safety are considered to be neither detectable nor destabilizing.

Nevertheless, the staff performed an evaluation of the likely magnitude of these impacts using available data. Radiological impacts are divided into those for "routine" or incident-free shipments (i.e., the shipment reaches its destination without incident) and those for shipments that involve an accident with a subsequent radiological release. In each case, the impact is expressed in cumulative dose for the transport workers and public. The results of the calculations are shown in Table 4-6. The details of the assumptions made in the analysis are discussed in Appendix K. In order to bound the impacts, a distance of 4800 km (3000 mi) was selected. Dose rates for incident-free shipment of high-activity LLW were assumed to be at the regulatory limits, and dose rates for incident-free shipment of low-activity LLW were assumed to be at one-tenth of regulatory limits. Radiological impacts of shipment of very low-level activity LLW were assumed to be negligible compared to shipments of high-level and low-level activity LLW. However, shipment of very low-level activity waste was considered in evaluating nonradiological transportation of LLW. With these assumptions and the additional assumptions listed in Appendix K, the results of the analysis should bound the transportation impacts for all decommissioning options for PWRs and BWRs.

Ramsdell et al. (2001) indicate that shipment of spent fuel by rail reduces the radiological impacts significantly (more than a factor of 10 for shipments from the northeast to Nevada). Similar reductions would be expected in the radiological impacts of the shipment of LLW from decommissioning if shipments were made by rail rather than by truck. Barge shipments of the high-activity waste could reduce the radiological impacts even further.

Nonradiological impacts: Nonradiological impacts of transportation of LLW include increased traffic and wear and tear on roadways. Decommissioning experience has been that the number of LLW shipments from a site averages much less than 1 per day. This number of shipments per day is not nearly large enough to have a detectable or destabilizing effect on traffic flow or road wear.

Nonradiological impacts of transportation accidents are typically expressed in terms of fatalities. RADTRAN estimates fatalities caused by traffic accidents using the distance traveled and average fatality rates per unit distance. Traffic accidents are not related to radioactivity; therefore, the impacts of transportation accidents should be based on the round-trip distance between the decommissioning site and the waste facility. For consistency, a 9600-km (6000-mi) round-trip distance is assumed for the fatality estimates shown in Table 4-6. Again, these numbers reflect the entire decommissioning period. The fatality estimates would be the same for shipments of any other commodity.

The following values may provide some perspective for evaluating the values in Table 4-6. A recent publication (Saricks and Tompkins 1999) gives average accident rates on interstate highways. The average accident rates for trucks are 3.15×10^{-7}, 3.66×10^{-7} and 6.54×10^{-7} per kilometer (5.07×10^{-7}, 5.89×10^{-7}, and 1.05×10^{-6} per mile) for highways in rural, suburban, and urban areas, respectively. The national average fatality rate for trucks is 5.5×10^{-9} fatalities per

Table 4-6. Impacts of Transportation of LLW from Decommissioning

	High-Activity Waste	Low-Activity Waste	Very Low-Activity Waste	Total
Number of Shipments during Decommissioning	227	84	360	671[a]
Incident-Free Transportation Impacts – Cumulative Dose, person-Sv (person-rem)				
Crew	0.496 (49.6)	0.184 (18.4)	--	0.680 (68.0)
Public along route	0.129 (12.9)	0.020 (2.00)	--	0.149 (14.9)
Onlookers	0.123 (12.3)	0.019 (1.90)	--	0.142 (14.2)
Total	0.748 (74.8)	0.223 (22.3)	--	0.971 (97.1)
Incident-Free Transportation Impacts – Latent Cancer Fatalities (LCF)				
Crew[b]	0.0198	0.00736	--	0.0272
Public along route[c]	0.0065	0.00100	--	0.00744
Onlookers[c]	0.0062	0.00096	--	0.00711
Total	0.0324	0.00931	--	0.0417
Accident Impacts				
Cumulative Dose, person-Sv (person-rem)	5.39×10^{-5} (5.39×10^{-3})	1.28×10^{-4} (1.28×10^{-2})	--	1.82×10^{-4} (1.82×10^{-2})
Nonradiological Fatalities	0.0120[d]	0.00465[d]	0.019[d]	0.0356[d,e]
Total				
Cumulative Dose, person-Sv (person-rem)	0.748 (74.8)	0.223 (22.3)	--	0.971 (97.1)
Fatalities	0.0419	0.0136	0.0190	0.0745[e]

(a) The total number of shipments during decommissioning may be significantly increased if State or local government agencies require removal of all structures and concrete from the site. However, the additional shipments would be uncontaminated material.
(b) Assuming 4.0×10^{-2} LCF/person-Sv (4.0×10^{-4} LCF/person-rem) for crew.
(c) Assuming 5.0×10^{-2} LCF/person-Sv (5.0×10^{-4} LCF/person-rem) for general public.
(d) Based on fatal accident rate of 5.5×10^{-9} per km (8.8×10^{-9} per mi).
(e) The number of fatalities will increase if there are additional shipments of uncontaminated material in proportion to the number of miles driven.

kilometer (8.8×10^{-9} fatalities per mile). Historically, the accident rate for activities at nuclear facilities has been lower than the national average for similar activities because of the industry emphasis on training and adherence to established procedures.

It is not likely that the actual nonradiological impacts of transportation accidents would be as high as indicated or that they would be either detectable or destabilizing.

The number of shipments into the decommissioning facility would be much smaller than the number of shipments from the facility. The concrete used to entomb a plant would be manufactured at a batch plant onsite, or the licensee would use local sources for the materials needed for entombing a facility. Shipments of materials into the facility during decommissioning or following the preparation for entombment of the facility would be minimal. It is anticipated that many of the shipments to the facility undergoing decommissioning, including shipments of equipment and heavy machinery, would come from local sources and, thus, the distance traveled would be minimal. Therefore, the staff concludes that transporting the materials to the site would not significantly impact the overall traffic volume or compromise the safety of the public,

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in impacts on transportation that are different from those found at other nuclear facilities.

4.3.17.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential transportation impacts of decommissioning activities. This information indicates that the transportation impacts are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that for all plants, the potential transportation impacts are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

4.3.18 Irreversible and Irretrievable Commitment of Resources

Irreversible commitments are commitments of resources that cannot be recovered, and irretrievable commitments of resources are those that are lost only for a period of time. The irreversible and irretrievable commitments of resources that are anticipated during the decommissioning process are similar to those that were considered in the FESs for facility construction permits and operating licenses. The FESs for plant operation cite uranium as the principal natural resource irretrievably consumed in facility operation. However, following permanent cessation of operations, uranium is no longer consumed. As discussed in Chapter 1, disposal of uranium as part of spent nuclear fuel is not within the scope of this Supplement. Other resources considered in some FESs include land, water, human resources, cultural, and threatened and endangered species.

4.3.18.1 Regulations

CEQ regulations at 40 CFR 1502.13 and NRC regulations at 10 CFR 51, Appendix A to Subpart A, state that an environmental impact statement include a discussion of any irreversible or irretrievable commitments of resources. In addition, there are regulations that deal with the use of land (addressed in Section 4.3.1, "Onsite/Offsite Land Use"), water use and quality (Sections 4.3.2 and 4.3.3), and air quality (Section 4.3.4). Disposal of uranium is not within the

scope of this document. Land devoted to LLW disposal sites or in industrial landfills is also not within the scope of this document and is addressed in the licensing documents for the disposal site.

4.3.18.2 Potential Impacts of Decommissioning Activities on Irretrievable Resources

Table E-3 in Appendix E indicates that decommissioning activities with the potential to impact irreversible and irretrievable commitment of resources include structural dismantlement; LLW packaging, storage, and disposal; and transportation.

An irreversible commitment of resources is defined as a loss that is detectable and destabilizing, such as when a species becomes extinct, or, in the case of mining, when ore is removed. Irretrievable commitments can be considered as a tradeoff. If a transportation corridor is constructed, the land uses are not available for as long as the corridor remains. The destabilizing impacts are those that adversely impact the resources discussed in this Supplement (Sections 4.3.1 through 4.3.17).

4.3.18.3 Evaluation

Although most FESs addressed primarily uranium fuel, other resources were discussed in some of the FESs. This included land used for plant buildings, components such as large underground concrete foundations, and certain other equipment considered irretrievable due to practical aspects of reclamation and/or radioactive decontamination. The use of the environment (air, water, and land) by the facilities was not deemed to represent significant irreversible or irretrievable resource commitments but rather a relatively short-term investment.

Whether land is considered to be an irretrievable resource depends largely on the decisions at the time of license termination. If the license is terminated for unrestricted use, then the land will be available for other uses, whether or not the decommissioning process returned the land to a "Greenfield" site or to an industrial complex. If ENTOMB1 is selected, license termination could still allow unrestricted access after 30 to 60 years. However, if the ENTOMB2 option is selected, the land under the facility will not be available for alternative uses and would be considered irretrievable.

The only other irretrievable resources that would occur during the decommissioning process would be materials used to decontaminate the facility (e.g., rags, solvents, gases, and tools), and fuel used for construction machinery and for transportation of materials to and from the site. However, these resources are minor.

Although the use of land, water, air, and fuel oil during decommissioning is minimal or nonexistent, the disposal of radioactive waste and nonradioactive waste would be considerable for some options, such as DECON to a "Greenfield" (nonindustrial) site. Even though the disposal of radioactive waste is outside the scope of this document, the volume of land required for radioactive waste disposal is estimated in Table 4-7 for the SAFSTOR and DECON options, based on data obtained from six plants. The quantities of waste shown in Table 4-7 for the two

ENTOMB options were estimated based on the scenarios described in Chapter 3. The greatest estimated volume of radwaste is from a facility that is being decommissioned to "Greenfield" (no structures remaining onsite). It is located in a State that does not allow disposal of the industrial waste within an in-state industrial waste site.

Table 4-7. Volumes of Land Required for LLW Disposal[a]

Decommissioning Option	Reactor Type	Volume of Land Required for LLW Disposal, m^3 (ft^3)	Plant Size (Electrical Capacity, MWe)
DECON	PWR	8000 - 10,000 (282,500 - 353,000)	1130 to 1825
	BWR	2000 (71,000)	240
SAFSTOR	PWR	600 - 45,000 (21,000 -1.5 million)	23 to 1437
	BWR	18,000 (636,000)	660
ENTOMB1	Either	<5000 (<177,000)	Variable
ENTOMB2	Either	<500 (<17,700)	Variable

(a) Data were available from a limited number of facilities and based on actual estimates provided by the licensees.

4.3.18.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on irreversible and irretrievable commitments of resources, including comments received on the draft of Supplement 1 of NUREG-0586. This information indicates that the impacts of decommissioning on irreversible and irretrievable commitments are neither detectable nor destabilizing. Therefore, the staff makes the generic conclusion that the impacts on irreversible and irretrievable commitments are SMALL. The staff has considered mitigation and concludes that no additional measures are likely to be sufficiently beneficial to be warranted.

4.4 References

10 CFR 20. Code of Federal Regulations, Title 10, *Energy*, Part 20, "Standards for protection against radiation."

10 CFR 50. Code of Federal Regulations, Title 10, *Energy*, Part 50, "Domestic licensing of production and utilization facilities."

10 CFR 51. Code of Federal Regulations. Title 10, Energy, Part 51, "Environmental protection regulations for domestic licensing and related regulatory functions."

10 CFR 71. Code of Federal Regulations, Title 10, *Energy*, Part 71, "Packaging and

transportation of radioactive material."

10 CFR 100. Code of Federal Regulations, Title 10, *Energy*, Part 100, "Reactor site criteria."

14 CFR 150. Code of Federal Regulations, Title 14, *Aeronautic and Space*, Part 150, "Airport noise compatibility planning."

24 CFR 51B. Code of Federal Regulations, Title 24, *Housing and Urban Development*, Part 51B, "Environmental criteria and standards."

29 CFR 1902. Code of Federal Regulations, Title 29, *Labor*, Part 1902, "State plans for the development and enforcement of State standards."

29 CFR 1910. Code of Federal Regulations, Title 29, *Labor*, Part 1910, "Occupational safety and health standards."

29 CFR 1926. Code of Federal Regulations, Title 29, *Labor*, Part 1926, "Safety and health regulations for construction."

29 CFR 1952. Code of Federal Regulations, Title 29, *Labor*, Part 1952, "Approved State plans for enforcement of State standards."

36 CFR 800. Code of Federal Regulations, Title 36, *Parks, Forests, and Public Property*, Part 800, "Protection of historic properties."

40 CFR 50. Code of Federal Regulations, Title 40, *Protection of Environment*, Part 50, "National primary and secondary ambient air quality standards."

40 CFR 51. Code of Federal Regulations, Title 40, *Protection of Environment*, Part 51, "Requirements for preparation, adoption, and submittal of implementation plans."

40 CFR 61. Code of Federal Regulations, Title 40, *Protection of Environment*, Part 61, "National emission standards for hazardous air pollutants; regulation of radionuclides."

40 CFR 81. Code of Federal Regulations, Title 40, *Protection of Environment*, Part 81, "Designation of areas for air quality planning purposes."

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40 CFR 1508. Code of Federal Regulations, Title 40, *Protection of Environment*, Part 1508, "Terminology and index."

49 CFR 171 - 177. Code of Federal Regulations, Title 49, *Transportation*, Parts 171-177, "General information, regulations, and definitions"; "Hazardous materials table, special provisions, hazardous materials, communications, emergency response information, and training requirements"; "Shippers--general requirements for shipments and packagings"; "Carriage by rail"; "Carriage by aircraft"; "Carriage by vessel"; "Carriage by public highway."

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4.5 Related Documents

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5.0 No-Action Decommissioning Alternative

The action discussed in this Supplement and in the *Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* (1988 GEIS; NRC 1988) is decommissioning. The only alternative to the action of decommissioning is not to decommission the facility. The option to restart the reactor is not considered to be an alternative to decommissioning because the regulations do not allow the licensee to reload fuel and restart the facility after submitting a certification that the fuel has been removed from the reactor vessel.

The alternative to decommissioning at the end of the licensing period is a "no action" alternative, implying that a licensee would simply abandon or leave a facility after ceasing operations. Once the facility permanently ceases operation, if the licensee does not conduct decommissioning activities to an extent that meets the license termination criteria in 10 CFR 20 Subpart E, then the license will not be terminated (although the licensee will not be authorized to operate the reactor). The licensee will be required to comply with the necessary requirements for the operating license. As a result, the environmental impacts for maintaining the nuclear reactor facility will be considered to be in the bounds of the appropriate, previously issued Environmental Impact Statements.

The objective of decommissioning is to restore a radiologically contaminated facility to a condition such that there is no unreasonable risk from the decommissioned facility to the public health and safety. The U.S. Nuclear Regulatory Commission (NRC) regulations do not allow the option of not decommissioning. Under NRC regulations, the original operating license for a nuclear power plant is issued for up to 40 years. The license may be renewed for additional 20-year periods if NRC requirements are met. However, at the end of the term of the license (whether it has been extended or not), the regulations require that the facility be decommissioned.

5.1 Reference

U.S. Nuclear Regulatory Commission (NRC). 1988. *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities.* NUREG-0586, NRC, Washington, D.C.

6.0 Summary of Findings and Conclusions

6.1 Summary of Findings

This chapter summarizes the findings and conclusions from the evaluation of environmental impacts related to decommissioning of permanently shutdown commercial nuclear power reactors. Table 6-1 presents each environmental issue that was evaluated and identifies whether the issue is considered generic or site-specific. Of the environmental issues assessed (see Table 6-1), most of the impacts are generic and SMALL for all plants regardless of the decommissioning activity and identified variables (see Appendix E for a list of the variables).

Two issues were identified that require a site-specific analysis: threatened and endangered species and environmental justice.

In accordance with the Endangered Species Act of 1973 (16 USC 1531 et seq.), the appropriate Federal agency (either the U.S. Fish and Wildlife Service or the National Marine Fisheries Service) must be consulted about the presence of threatened or endangered species. Informal consultation will be initiated by the U.S. Nuclear Regulatory Commission (NRC) staff with the appropriate service after the licensee announces permanent cessation of operations. It is expected that any formal or informal consultation will be completed prior to the licensee beginning major decommissioning activities, which can occur 90 days after the submission of the post-shutdown decommissioning activities report (PSDAR). At that time, it will be determined whether such species could be affected by decommissioning activities and whether formal consultation will be required to address the impacts. Each State should also be consulted about its own procedure for considering impacts to State-listed species.

Executive Order 12898 (59 FR 7629), dated February 16, 1994, directs Federal executive agencies to consider environmental justice under the National Environmental Policy Act of 1969 (NEPA). Although the NRC is an independent agency, the Commission has committed to undertake environmental justice reviews. Subsequent to the submittal of the PSDAR, the NRC staff will consider the impacts related to environmental justice from decommissioning activities.

Four issues were determined to be, depending on the circumstances, either generic or site-specific: land use, aquatic ecology, terrestrial ecology, and cultural and historic resources. Impacts resulting from onsite land use, impacts to aquatic and terrestrial resources resulting from activities occurring within the facility's operational areas, and impacts to cultural or historic resources resulting from activities within the facility operational area were determined to be generic and SMALL.

Table 6-1. Summary of the Environmental Impacts from Decommissioning Nuclear Power Facilities

Issue	Generic	Impact
Onsite/Offsite Land Use		
- Onsite land use activities	Yes	SMALL
- Offsite land use activities	No	Site-specific
Water Use	Yes	SMALL
Water Quality		
- Surface water	Yes	SMALL
- Groundwater	Yes	SMALL
Air Quality	Yes	SMALL
Aquatic Ecology		
- Activities within the operational area	Yes	SMALL
- Activities beyond the operational area	No	Site-specific
Terrestrial Ecology		
- Activities within the operational area	Yes	SMALL
- Activities beyond the operational area	No	Site-specific
Threatened and Endangered Species	No	Site-specific
Radiological		
- Activities resulting in occupational dose to workers	Yes	SMALL
- Activities resulting in dose to the public	Yes	SMALL
Radiological Accidents	Yes	SMALL
Occupational Issues	Yes	SMALL
Cost	NA[a]	NA
Socioeconomic	Yes	SMALL
Environmental Justice	No	Site-specific
Cultural and Historic Resource Impacts		
- Activities within the operational areas	Yes	SMALL
- Activities beyond the operational areas	No	Site-specific
Aesthetics	Yes	SMALL
Noise	Yes	SMALL
Transportation	Yes	SMALL
Irretrievable Resources	Yes	SMALL

(a) A decommissioning cost assessment is not a specific National Environmental Policy Act (NEPA) requirement. However, an accurate decommissioning cost estimate is necessary for a safe and timely plant decommissioning. Therefore, this Supplement includes a decommissioning cost evaluation, but the cost is not evaluated using the environmental significance levels nor identified as a generic or site-specific issue.

Impacts resulting from offsite land use to support decommissioning activities, impacts to aquatic and terrestrial resources resulting from activities occurring outside the facility's operational areas, and impacts to cultural, historic or archeological resources resulting from activities beyond the operational areas cannot be evaluated generically and would require a site-specific analysis before undertaking the activity. These are termed conditionally site-specific.

Before a licensee conducts any decommissioning activity that might result in the disturbance of historic properties or archeological resources outside the site operational area, the NRC will, in accordance with the National Historic Preservation Act of 1966, as amended (16 USC 470 et seq.), consult with the appropriate State (or Tribal) Historic Preservation Officer to evaluate potential impacts.

The issue of cost was addressed in this Supplement but was not evaluated.

The staff also determined that the issue of long-term radiological aspects of Rubblization or onsite disposal of slightly contaminated material could not be evaluated generically and would require a site-specific analysis. The site-specific analysis would be conducted at the time the license termination plan (LTP) for the site is submitted.

For the 19 reactors listed in Table F-1 that have permanently ceased operation during the period 1963 through 1997, the staff has determined that no issue or activity must be re-evaluated immediately, provided that the licensee does not change the decommissioning option previously chosen. The NRC staff conducted a detailed environmental review on a number of these facilities prior to 1996 as part of the decommissioning plan review. Licensees for several of these reactors have submitted LTPs for NRC review and approval, and the staff has evaluated or is evaluating site-specific environmental impacts as part of that review. Therefore, for many of the 19 facilities, a site-specific assessment has been performed. Because decommissioning is substantially underway at all 19 reactors, the impacts for the issue of environmental justice have already occurred and an evaluation at the present time would provide little value and opportunity for mitigation. Impacts on threatened and endangered species are considered on an ongoing basis and the issuance of this Supplement would not accelerate a review of the issue solely because the issue is one that cannot be evaluated generically. The staff will continue to conduct site-specific consultations with the appropriate resource agency, as the need arises.

Therefore, the NRC has determined that it is not necessary at this time to conduct an evaluation of the environmental justice or impacts on threatened and endangered species at the 19 permanently shutdown reactors listed in Table F-1. However, should a licensee choose a different decommissioning option from its current choice (e.g., SAFSTOR rather than DECON),

then the site-specific issues would need to be considered prior to undertaking a decommissioning activity not previously evaluated.

For the 19 facilities listed in Table F-1 that have initiated decommissioning, as well as for any facilities that permanently cease operation in the future, any planned decommissioning activity would require a site-specific analysis prior to undertaking the proposed activity (see Section 1.5) if the activity:

- results in an impact outside the range of impacts postulated by this Supplement or
- raises environmental issues that were not considered in this Supplement or
- involves an issue determined to be site specific or conditionally site-specific as described above in this Supplement or
- involves a combination of the above.

6.2 Conclusions

A licensee undergoing or planning decommissioning of a nuclear reactor facility may use this Supplement in its evaluation of the environmental consequences from decommissioning activities. The impacts identified in this Supplement are designed to span the range of impacts for all commercial power reactor facilities that have permanently shut down as well as for the reactor facilities that are currently operating, including the facilities that have, or may, renew their operating license beyond the original 40-year license.

For those issues that have been determined to be generic, licensees may proceed with the decommissioning activity without further analysis provided that the impacts resulting from those activities fall within the range of impacts as described in Chapter 4. However, if the impacts of an activity fall outside the range predicted in Chapter 4, or if the activity results in impacts to environmental issues not considered in this Supplement, or if the impact involves an environmental issue determined to be conditionally site-specific as defined above, then the activity cannot be performed until a further site-specific analysis is completed along with a license-amendment request and NRC has approved the license amendment (the license-amendment request will provide an opportunity for a public hearing).

6.3 References

Endangered Species Act of 1973, as amended, 16 USC 1531 et seq.

Executive Order 12898. 1994. "Environmental Effects of Federal Programs on Minority and Low-Income Populations." 59 FR 7629, February 16, 1994.

National Environmental Policy Act (NEPA) of 1969, as amended, 42 USC 4321 et seq.

National Historic Preservation of 1966, as amended, 16 USC 470 et seq.

Appendix A

Appendixes A and B have been moved and redesignated as Appendixes N and O. All comments and responses, whether written or oral, are now contained in Appendixes N, O, and P, which comprise Volume 2 of this Supplement.

Appendix B

Appendixes A and B have been moved and redesignated as Appendixes N and O. All comments and responses, whether written or oral, are now contained in Appendixes N, O, and P, which comprise Volume 2 of this Supplement.

Appendix C

Contributors

Appendix C

Contributors

The overall responsibility for the preparation of this Supplement to the Generic Environmental Impact Statement (GEIS) on Decommissioning was assigned to the Office of Nuclear Reactor Regulation (NRR), U.S. Nuclear Regulatory Commission (NRC). This Supplement was prepared by members of the NRR with assistance from other NRC organizations and the Pacific Northwest National Laboratory.

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(d) Currently with the Office of Nuclear Regulatory Research, NRC.

Appendix D

Further Discussion of Out-of-Scope Activities

Appendix D

Further Discussion of Out-of-Scope Activities

Various activities that are performed during decommissioning may seem intuitively to be part of the decommissioning process. However, they are not considered within the scope of this Supplement because these activities have already received an environmental review during the promulgation of the U.S. Nuclear Regulatory Commission (NRC) regulations governing such activities. They are reviewed and regulated by the NRC under other regulations. These activities include the following:

- Independent Spent Fuel Storage Installation (ISFSI): construction/maintenance/decommissioning: An ISFSI is a facility designed and constructed for the interim storage of spent nuclear fuel and other radioactive materials associated with spent fuel storage. The ISFSI may be located at the same site as the nuclear power facility or at another location. ISFSIs are used by operating plants that require increased spent fuel storage capacity because their spent fuel pools have reached their capacity and the U.S. Department of Energy (DOE) facility for disposing of spent fuel and high-level nuclear waste is not yet available. Decommissioning facilities may use ISFSIs as an alternative to leaving the fuel in the spent fuel pool while waiting for DOE to take ownership of the spent fuel. Licensees that remove the spent fuel from their pools and place it in an ISFSI can then complete the decommissioning process on the power-generation facilities and subsequently terminate the facility license. In some instances, the license for the nuclear power reactor can be terminated while the ISFSI, which has a separate license and is located on the facility site, would continue to be regulated by the NRC.

  An ISFSI can be operated either under the same license that is used for the operating or decommissioning facility (called a "Part 50 license," referring to 10 CFR Part 50), or under a site-specific license (called a "Part 72 license," referring to 10 CFR Part 72). Regulations for the licensing and operation of an ISFSI, including quality assurance and quality control requirements, are found in 10 CFR Part 72. If a licensee chose to operate the ISFSI under a Part 50 license, they could, by way of a license-amendment request, change the ISFSI to a Part 72 license, thus allowing termination of the Part 50 license at the end of the reactor facility decommissioning process.

The decommissioning of the ISFSI is also handled separately from the decommissioning of the nuclear power facility. The 1988 Generic Environmental Impact Statement (GEIS) (NRC 1988) contained a section on decommissioning of ISFSIs, which is not updated in this Supplement.

- Spent fuel storage and maintenance: The Commission has independently, in a separate proceeding, the "Waste Confidence Proceeding," made a finding that there is:

  > reasonable assurance that, if necessary, spent fuel generated in any reactor can be stored safely and without significant environmental impacts for at least 30 years beyond the licensed life for operation (which may include the term of a revised license) of that reactor at its spent fuel storage basin, or at either onsite or offsite independent spent fuel storage installations. (54 FR 39767)

  The Commission has committed to review this finding at least every 10 years. In its most recent review, the Commission concluded that experience and developments since 1990 were not such that a comprehensive review of the Waste Confidence Decision was necessary at that time (64 FR 68005). Accordingly, the Commission reaffirmed its finding of insignificant environmental impacts cited above. This finding is codified in the Commission's regulations at 10 CFR 51.23(a). The operation of a spent fuel pool or an ISFSI is not uniquely linked to decommissioning. All operating nuclear power facilities have spent fuel pools and some (with the number anticipated to increase) have ISFSIs generally located adjacent or near to the power reactor facility.

- Spent fuel transport and disposal away from the reactor location: The temporary storage or future permanent disposal of spent fuel at a site other than the reactor site is not within the scope of this Supplement. Licensees are prohibited from shipping spent fuel from one reactor's spent fuel pool to another's without NRC approval. Amendment of one or both of the facilities' licenses would be required before fuel transfer.

  Transportation of spent fuel and other high-level nuclear wastes is governed by regulations in 10 CFR Part 71, "Packaging and Transportation of Radioactive Material." Disposal of spent fuel and high-level wastes (HLW) are governed by the Nuclear Waste Policy Act (NWPA) of 1982, as amended, which defined the goals and structure of a program for permanent, deep geologic repositories for the disposal of high-level radioactive waste and non-reprocessed spent fuel. Under this Act, the DOE is responsible for developing permanent disposal capacity for spent fuel and other high-level nuclear wastes. On July 9, 2002, the U.S. Congress approved Yucca Mountain as the first long-term geologic repository for spent nuclear fuel and high-level radioactive waste. A HLW repository will be built and operated by DOE and licensed by the NRC. Title 10 CFR Part 61 contains rules

governing the licensing to receive and possess source, special nuclear, and by-product material at a geological repository operations area that is sited, constructed, or operated in accordance with the NWPA (1982). However, the Commission proposes to supersede the generic criteria in Part 60 for disposal at a waste repository with specific criteria in a new 10 CFR Part 63 issued on February 22, 1999 (64 FR 8640).

- Interim storage of Greater-than-Class-C (GTCC) Waste: The NRC regulations at 10 CFR 61.55 define three classes of low-level waste (LLW) (A, B, and C) that are suitable for near-surface disposal. Class C waste is required to meet the most rigorous disposal requirements. The LLW that exceeds the concentration limits set for Class C waste is referred to as GTCC waste. Typically, GTCC waste is composed of activated metal components and process wastes.

  On October 11, 2001 the NRC amended its regulations (in 66 FR 51823), to permit interim storage of GTCC waste used or generated by commercial power reactors within an ISFSI or monitored retrievable storage (MRS) facility. This change permits the co-locating of spent fuel and solid reactor-related GTCC waste in different casks and containers within the ISFSI or MRS. Commingling of spent fuel and GTCC waste in the same storage cask is not permitted, except on a case-by-case basis. Ultimately, GTCC waste must be disposed of in a geologic repository.

- LLW disposal at a licensed LLW site or treatment of LLW at compactor facilities: The disposal of LLW is not within the scope of this Supplement. LLW is defined as any radioactive waste that is not classified as HLW, spent nuclear fuel, transuranic waste,[a] or uranium or thorium mill tailings. LLW often contains small amounts of radioactivity dispersed in large amounts of material, but may also have activity levels requiring shielding and remote handling. LLW that is generated during decommissioning is usually composed of the following material contaminated with radionuclides: rags, papers, filters, solidified liquids, ion-exchange resins, tools, equipment, discarded protective clothing, dirt, construction rubble, concrete, and piping.

  Regulations related to LLW disposal are in 10 CFR Part 61 and 10 CFR Part 20, Subpart K. A final GEIS supporting the regulations in 10 CFR Part 61, was published in 1982 as "Final Generic Environmental Impact Statement for 10 CFR Part 61," NUREG-0945 (NRC 1982). A license for the LLW disposal site is not issued until the applicant provides an environmental report (ER) indicating that the applicant's proposed disposal site, design,

(a) Transuranic waste contains man-made elements heavier than uranium that decay by emitting alpha particles. Such waste is produced during reactor fuel assembly, weapons fabrication, and chemical processing operations.

operations, site closure, and post-closure institutional controls are adequate to protect public health and safety. The licensee for the LLW site must show that there is reasonable assurance that (1) the general population will be protected from releases of radioactivity, (2) that individual inadvertent intruders are protected, (3) that standards for radiation protection in 10 CFR Part 20 are met, and (4) that the long-term stability of the disposed waste and the disposal site will be achieved and will eliminate, to the extent practical, the need for ongoing active maintenance of the disposal site following closure. The ER will be reviewed by the NRC and the impacts of LLW disposal evaluated in an Environmental Impact Statement (EIS) that is written for the specific LLW site. The technical requirements for land-disposal facilities are covered in Subpart D of 10 CFR Part 61. The financial assurance requirements are covered in Subpart E of 10 CFR Part 61.

- Activities related to the ENTOMBMENT Period:

  On October 16, 2001, the Commission issued an advance notice of proposed rulemaking (ANPR) inviting input from stakeholders on "Entombment options for Power Reactors" (66 FR 52551). Consistent with the environmental evaluation of the DECON and SAFSTOR decommissioning options, the staff has limited its environmental evaluation of ENTOMB to those issues related to activities necessary to prepare the facility for entombment.

  Issues and resulting impacts related to the ENTOMB option after the facility begins entombment, such as NRC oversight and monitoring requirements, durability of institutional controls and engineered barriers, indefinite retention onsite of radioactive materials, and other long-term site-specific issues are outside the scope of this Supplement.

  A future environmental assessment in support of NRC rulemaking related to the entombment options may address these issues depending on the proposed changes to the regulations.

- Activities following license termination under restricted use conditions: Licensees are allowed by regulations in 10 CFR Part 20, Subpart E, "Radiological Criteria for License Termination," to release the site for restricted use. The impacts following a restricted release license termination will not be considered by this Supplement because the licensee is required to conduct a site-specific analysis to support development of an NRC site-specific EIS.

- Activities and impacts from living or working on the site after license termination: Analysis of radiological impacts from unrestricted use after decommissioning and license termination are presented in NUREG-1496, *Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities* (NRC 1997). This GEIS analyzed regulatory

alternatives for establishing radiological criteria for decommissioning structures and lands of licensed facilities. The scope included both radiological and nonradiological impacts on human health and safety, including radiation exposure resulting from occupancy of site buildings and residence on site lands following decommissioning and license termination.

D.1 References

10 CFR 20. Code of Federal Regulations, Title 10, *Energy*, Part 20, "Standards for protection against radiation."

10 CFR 50. Code of Federal Regulations, Title 10, *Energy*, Part 50, "Domestic licensing of production and initialization facilities."

10 CFR 51. Code of Federal Regulations, Title 10, *Energy*, Part 51, "Environmental protection regulations for domestic licensing and related regulatory functions."

10 CFR 61. Code of Federal Regulations, Title 10, *Energy*, Part 61, "Licensing requirements for land disposal of radioactive waste."

10 CFR 63. Code of Federal Regulations, Title 10, *Energy*, Part 63, "Disposal of high-level radioactive wastes in a geologic repository at Yucca Mountain, Nevada."

10 CFR 71. Code of Federal Regulations, Title 10, *Energy*, Part 71, "Packaging and transportation of radioactive material."

10 CFR 72. Code of Federal Regulations, Title 10, *Energy*, Part 72, "Licensing requirements for the independent storage of spent nuclear fuel and high-level radioactive waste."

54 FR 39767. "10 CFR Part 51 Waste Confidence Decision Review." *Federal Register*. September 28, 1989.

64 FR 8640. "10 CFR Parts 2, 19, 20, 21, 30, 40, 51, 60, 61, and 63 Disposal of High-Level Radioactive Wastes in a Proposed Geologic Repository at Yucca Mountain, Nevada." *Federal Register*. February 22, 1999.

64 FR 68005. "Waste Confidence Decision Review." *Federal Register*. December 6, 1999.

66 FR 51823. "Interim Storage for Greater Than Class C Waste 10 CFR Parts 30, 70, 72, and 150." *Federal Register*. October 11, 2001.

66 FR 52551. "Entombment Options for Power Reactors." *Federal Register.* October 16, 2001.

Nuclear Waste Policy Act of 1982, as amended, 42 USC 10.101 et seq.

U.S. Nuclear Regulatory Commission (NRC). 1982. *Final Generic Environmental Impact Statement for 10 CFR Part 61.* NUREG-0945, NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1988. *Final Generic Environmental Impact Statement for Decommissioning of Nuclear Facilities.* NUREG-0586, NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1997. *Final Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities.* NUREG-1496, Vol. 1, NRC, Washington, D.C.

Appendix E

Evaluation Process for Identifying the Environmental Impacts of Decommissioning Activities

Appendix E

Evaluation Process for Identifying the Environmental Impacts of Decommissioning Activities

This appendix describes the process that the staff used to determine the environmental impacts from decommissioning nuclear power facilities. Figure E-1 is a flowchart showing the evaluation process. The staff first created an initial list of environmental issues and decommissioning activities that this Supplement should address (Table E-1). The initial list of environmental issues was developed from the issues identified in the 1988 GEIS and the list specified in 10 CFR Part 51, Subpart A, Appendix B, for license renewal. The initial list of decommissioning activities was based on experience and the literature discussed in Section 3.2 of this Supplement. The staff used these initial lists of environmental issues and decommissioning activities for discussions during the scoping process (Section 1.3). At the conclusion of the scoping process and after conducting visits to six sites, the staff refined these two lists, based on comments from the public, the industry, the specific sites visited, the States, and other Federal agencies. During the scoping process, the staff visited the sites listed in Table E-2 and gathered information about the sites' decommissioning experiences. The sites were chosen to represent a variety of types of sites in various stages of decommissioning.

The staff designed a two-tier matrix system to document the evaluation process. In the Tier 1 (Table E-3) matrix, the environmental issues are listed on the horizontal axis and the decommissioning activities are listed on the vertical axis. Each activity in the list is grouped into broad categories designed to include a variety of specific activities. The list of activities is comprehensive and includes new technologies that were considered in this Supplement. Other innovative decommissioning options or activities not included in this document are expected to be developed by licensees in the future. Such options or activities do not fall under the conclusions of this Supplement and would need to be analyzed on a site-specific basis.

After compiling the environmental issue and decommissioning activity lists, the staff assessed which activities might have environmental impacts for each of the issues. The Tier 1 matrix (Table E-3) also shows the result of this evaluation. The Tier 1 matrix identifies impacts that occur for issues related to specific activities during the decommissioning process. In developing the Tier 1 matrix, the staff resolved whether the issue applies to the activity and whether there were potential environmental impacts. If the answer was "yes," the impacts in the matrix were marked with an "X" to designate the need for an analysis in the Supplement. For example, the transfer of the fuel from the reactor vessel to the spent fuel pool (an activity that occurs inside

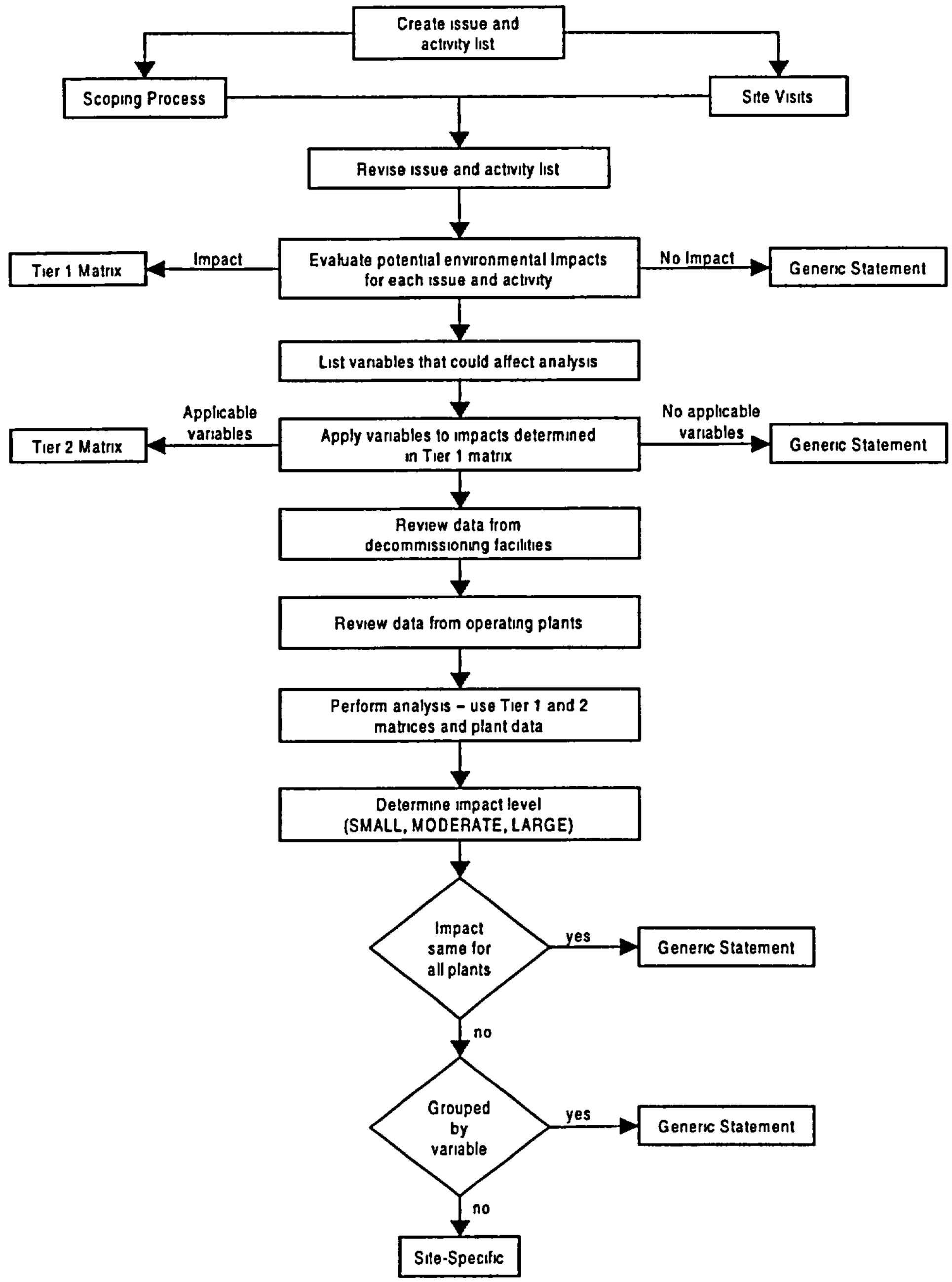

Figure E-1. Environmental Impact Evaluation Process

Table E-1. First- and Second-Tier Matrices Issues and Activities

Issues
Onsite/offsite land use
Water use
Water quality
Air quality
Aquatic ecology
Terrestrial ecology
Threatened and Endangered Species
Radiological
Radiological accidents
Occupational issues
Cost
Socioeconomics
Environmental justice
Cultural impacts
Aesthetic issues
Noise

Activities
Remove fuel
Organizational changes
Stabilization
Post-shutdown surveys
Create nuclear island
Chemical decontamination of primary loop
Large component removal
Storage preparation activities for SAFSTOR
Storage (SAFSTOR)
Decontamination and Dismantlement phases of DECON, SAFSTOR, and ENTOMB1
System dismantlement
Structure dismantlement
Entombment
Low-level waste packaging and storage
Transportation
License termination activities

Table E-2. Site Visits

Nuclear Plant	Description	Plant Type	Thermal Power	Decommissioning Method
Big Rock Point	Single nuclear unit	BWR[(a)]	240 MW	DECON
Humboldt Bay, Unit 3	Single nuclear plant at multi-unit fossil fuel facility	BWR	200 MW	SAFSTOR
Maine Yankee	Single nuclear unit	PWR[(b)]	2700 MW	DECON
Rancho Seco	Single nuclear unit	PWR	2772 MW	SAFSTOR
Trojan	Single nuclear unit	PWR	3411 MW	DECON
Zion, Units 1 and 2	Multiple nuclear units	PWR	3250 MW	SAFSTOR

(a) boiling water reactor.
(b) pressurized water reactor.

the facility) would not result in aesthetic or noise issues. On the other hand, this activity would result in a radiation dose to the workers (radiological) and could potentially cause a radiological accident. In some cases, correlation between the activity and the issue was not evident. In these cases, the matrix was marked conservatively to ensure further analysis of the impact. This is the case with the issues of water use for the activity of transferring fuel to the spent fuel pool. The water that is used in this process is very small compared to the amount of water used to cool the reactor during operations. However, the matrix was marked to ensure that the water-use issue was addressed completely in this Supplement.

Typically, environmental impact statements would consider transportation as an issue and not as an activity. However, the staff determined that in the case of decommissioning nuclear power reactors, transportation is an activity, not an issue. Because there are several transportation-based impacts related to decommissioning nuclear power facilities, transportation was addressed in its own section (4.3.17) in this Supplement.

After completing the Tier 1 matrix, the next step was to identify the variables that might affect the environmental impact for a specific issue. These variables include some of the obvious differences between reactor facilities, such as whether the facility is a pressurized water reactor, boiling water reactor, or other type of reactor, whether it is a multi-unit site and what type of cooling system is used. The staff also considered variables that would impact a licensee's decision concerning types of activities or how an activity would be conducted. For example, the proximity of the facility to a barge slip or railroad might affect a licensee's decision to remove the steam generator or other large components intact and ship them to a waste site. If the barge slip needs additional dredging or an additional railroad line needs to be installed, then the environmental impacts may change. Table E-4 lists the variables, their abbreviations as they appear in the Tier 2 matrix (Table E-5), and the characteristics, if appropriate, for each variable.

The staff then considered each of the impact areas identified in the Tier 1 matrix, and determined if the variables influenced the environmental impacts. If no change would occur, then the "X" in the box was retained to signify that the variables do not change the analysis. If a change would occur, then the staff needs a second determination as to which variables could significantly change the impact. Variables that could significantly change the impact were listed by their abbreviation in the appropriate box in the matrix (see Table E-3 for the abbreviations). By resolving these questions, the staff developed the Tier 2 matrix shown in Table E-5. The staff used the Tier 2 matrix as the starting point for the analysis of the environmental impacts of the decommissioning activities for each of the applicable issues and variables.

The analyses that are presented in the following sections were based on the information in the Tier 2 matrix. The data used in the analyses was obtained from several sources:

- documents such as post-shutdown decommissioning activity reports, final environmental statements, environmental reports, and license termination plans for permanently shutdown and decommissioning facilities

- site visits

- information gathered from permanently shutdown and decommissioning facilities with the assistance of the Nuclear Energy Institute

- currently operating facilities (primarily from NUREG-1437 [NRC 1996]).

The analyses in this Supplement include data from both operating and decommissioning facilities in order to appropriately span the range of impacts so that future decommissioning facilities could consider using this Supplement. The data from the decommissioning facilities was used to determine whether an activity and associated issue could be considered generic. The reason for including the operating facilities is that they will eventually decommission. Also, many of the plants that have decommissioned were the smaller, older facilities.

E.1 References

10 CFR 51. Code of Federal Regulations, Title 10, *Energy*, Part 51, "Environmental protection regulations for domestic licensing and related regulatory functions."

U.S. Nuclear Regulatory Commission (NRC). 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG-1437, NRC, Washington, D.C.

Table E-3. Tier 1 Matrix - Decommissioning Activities and Issues

Activities	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Radiological Accidents	Occupational	Cost	Socioeconomic	Environmental Justice	Cultural Impacts	Aesthetic issues	Noise	Irretrievable Resources
1. Remove Fuel																	
- Transfer fuel to spent fuel pool		X	X					X	X	X							
- Drain primary system			X					X	X	X	X						
- Process liquid			X					X	X	X	X						
2. Organizational Changes																	
- Reduce staff		X						X			X	X	X				
- Employ contractor or other additional staff		X		X				X			X	X	X				
- Adjust site training								X	X	X	X						
- Changes to licensing basis - site-specific											X						
3. Stabilization																	
- Drain and flush system			X	X				X	X	X	X						
- Isolate systems, structures, and components that are no longer required				X				X		X	X						
- Rewiring of site to eliminate unneeded electrical circuits						X	X	X		X	X			X			
4. Post-Shutdown Surveys																	
- Baseline surveys for the decontamination work								X			X						
- Continual surveys								X			X						
5. Create Nuclear Island																	
- Install electrical power supply to spent fuel pool								X		X	X						
- Reduce the security area to just that around the fuel											X						
- Change security function											X						

"X" indicates where there may be am impact from decommissioning activities.

Table E-3. (contd)

Activities	Issues: Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Radiological Accidents	Occupational	Cost	Socioeconomic	Environmental Justice	Cultural Impacts	Aesthetic issues	Noise	Irretrievable Resources
- Install or modify chemistry controls										X							
- Move old or install new security-related equipment								X		X	X						
6. Chemical Decontamination of primary loop																	
- Cutting, chemicals in, chemicals out, cleanup/decon								X	X	X	X						
7. Large Component Removal																	
- Remove reactor vessel and internals intact or cut up	X	X				X	X	X	X	X	X			X			
- Steam generator and other large components removed intact or cut up	X					X	X	X	X	X	X			X			
8. Storage Preparation Activities for SAFSTOR																	
- Establish a reactor coolant system vent pathway				X				X		X	X						
- Establish containment vent pathway				X				X		X	X						
- De-energize systems, put in monitors where they are needed								X		X	X						
- Perform a radiological assessment								X			X						
9. Storage (SAFSTOR)																	
- Monitor systems and radiation levels etc.								X			X						
- Do preventive and corrective maintenance on SSCs								X		X	X						
- Maintain the security system											X						

"X" indicates where there may be an impact from decommissioning activities.

Table E-3. (contd)

Activities	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Radiological Accidents	Occupational	Cost	Socioeconomic	Environmental Justice	Cultural Impacts	Aesthetic issues	Noise	Irretrievable Resources
- Maintain effluent and environmental monitoring programs				X							X						
10. Decontamination and Dismantlement phases of DECON, SAFSTOR, and ENTOMB 1																	
- Chemical decontamination (surface/specific components)								X	X	X	X						
- Decontamination of piping inside walls								X	X	X	X						
- High-pressure water sprays of surface		X	X					X	X	X	X						
- Remove contaminated soil from specific areas						X	X	X		X	X			X			
- Do preventive and corrective maintenance on SSCs								X		X	X						
- Maintain the security system											X						
- Maintain effluent and environmental monitoring programs				X							X						
11. System Dismantlement																	
- Cut out radioactive piping								X	X	X	X						X
- Remove large and small tanks or other radioactive components from the facility								X	X	X	X						X
12. Structure Dismantlement																	
- Rubblization	X	X	X	X				X		X	X				X	X	X
- Remove structures that were necessary for plant operation	X	X		X	X	X	X	X	X	X	X				X	X	X

"X" indicates where there may be an impact from decommissioning activities.

Table E-3. (contd)

Activities	Issues																
	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Radiological Accidents	Occupational	Cost	Socioeconomic	Environmental Justice	Cultural Impacts	Aesthetic issues	Noise	Irretrievable Resources
13. Entombment																	
- Install engineered barriers				X				X		X	X				X	X	
- Disconnect operational systems (e.g. electrical and fire protection)								X		X	X						
- Remove all radioactive material that is outside of containment								X		X	X					X	
- Place material inside containment								X		X	X						
- Lower containment ceiling (optional)		X		X				X	X	X	X						
- Entomb facility in concrete		X		X						X	X				X	X	
14. LLW packaging and storage	X							X	X	X	X						X
15. Transportation																	
- Large components				X				X	X	X	X		X				X
- LLW				X				X	X	X	X		X				X
- Equipment into site				X							X						
- Backfill trucked into site				X							X						X
- Nonradioactive waste				X							X						X
16. License Termination Activities																	
- Complete final radiation survey								X		X	X						
- Partial site release								X			X						

"X" indicates where there may be an impact from decommissioning activities.

Table E-4. Tier 2 Matrix Variables

Variable Abbreviation	Variable	Variable Characteristics
Type	Type of plant	PWR, BWR, HTGR, FBR
Size	Size of plant	Based on the facility thermal power capability
Loc	Population charactenstics	Rural, urban
Env	Envronmental features	Coastal, desert, lake, nver shoreline, other
Cool Sys	Cooling system type	Closed cycle, once-through cooling
Cool	Cooling water source	Reservoir, lake, nver or creek, ocean, canal, bay, pond, canal, sewage treatment plant
Grdwater	Groundwater usage/proximity to groundwater	
Fuel Loc	Fuel location - as a function of time	Spent fuel pool, ISFSI, away from reactor
Ops	Off-normal radiological operational events	Failed or leaking fuel, contaminated soil
Intenm Time	Time between last shutdown and initiation of decommissioning	
Decom Opt	Decommissioning option	SAFSTOR, DECON, ENTOMB
Store Time	Duration of storage period for plants in deferred DECON/SAFSTOR	
Struct	Disposition of structures dunng decommissioning	Remain onsite, sent to a LLW site or vendor, entombed, landfill, rubblized
LLW	Distance traveled for disposal of LLW	
Gas Emissions	Method used to control gaseous radioactive effluents	
Land Mass	Land mass (footpnnt) of the site	
Culture	Cultural resources	Known/unknown, present/absent
Multi-Unit	Single unit versus multi-unit sites with other operating units	
Trans Prox	Proximity of barge/train transportation	

Table E-5. Tier 2 Matrix - Decommissioning Activities, Issues, and Variables

Activities	Issues																
	Onsite/Offsite Land Use	**Water Use**	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occupational Issues	Cost	Socioeconomic	Environmental Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
1. Remove fuel																	
Transfer fuel to spent fuel pool		X	X					Ops; Interim Time	Ops; Interim Time	X							
Drain primary system			X					Ops; Interim Time; Decom Opt; Store Time	Ops; Interim Time; Decom Opt; Store Time	X	Interim Time; Decom Opt; Store Time						
Process liquid			X					Ops; Interim Time	Ops; Interim Time	X	Type; Size						
2. Organizational changes																	
Reduce staff		X						Type; Size			Type; Size; Decom Opt; Store Time	Size; Loc; Multi-Unit	Size; Loc; Multi-Unit				
Employ contractor or other additional staff		X		Size Loc; Decom Opt				Type; Size; Decom Opt; Store Time			Type; Size, Decom Opt; Store Time	Type; Size; Loc; Multi-Unit	Type; Size; Loc; Multi-Unit				

"X" indicates that none of the variables change the analysis.

Table E-5. (contd)

Activities	Issues																
	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
Adjust site training								Type; Size; Decom Opt; Store Time	X	X	Type; Size; Decom Opt; Store Time						
Changes to licensing basis - site-specific											Type; Size; Decom Opt; Store Time						
3. Stabilization																	
Drain and flush system			X	X				Type; Size; Ops; Interim Time; Decom Opt; Store Time	Type; Size; Ops; Interim Time; Decom Opt; Store Time	Type; Size; Ops; Interim Time; Decom Opt; Store Time	Type; Size; Ops; Interim Time; Decom Opt; Store Time						

"X" indicates that none of the variables change the analysis.

Table E-5. (contd)

Activities	Issues																
	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
Isolate systems, structures, and components that are no longer required				X				Type; Size; Ops; Interim Time; Decom Opt; Store Time		Type; Size, Ops; Interim Time; Decom Opt; Store Time	Type; Size; Ops; Interim Time; Decom Opt; Store Time						
Rewiring of site to eliminate unneeded electrical circuits						Loc; Env; Land Mass	Loc; Env; Land Mass	Type; Size; Ops; Interim Time; Decom Opt; Store Time		Type; Size; Decom Opt	Type; Size; Ops; Interim Time; Decom Opt; Store Time			Loc; Land Mass			

"X" indicates that none of the variables change the analysis.

Table E-5. (contd)

Activities	Issues																
	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
4. Post-shutdown surveys																	
Baseline surveys for the decontamination work								Type; Size; Ops; Interim Time; Decom Opt; Land Mass			Type; Size; Ops; Interim Time; Decom Opt; Land Mass						
Continual surveys								Type; Size; Ops; Interim Time; Decom Opt; Store Time; Land Mass			Type; Size; Ops; Interim Time; Decom Opt; Land Mass						
5. Create nuclear island																	
Install electrical power supply to spent fuel pool								Ops; Interim Time		Size	X						
Reduce the security area to just that around the fuel											X						

"X" indicates that none of the variables change the analysis.

Table E-5. (contd)

Activities	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
	Issues																
Change security function											X						
Install or modify chemistry controls										Size							
Move old or install new security-related equipment								Ops; Interim Time		Size, Land Mass	X						
6. Chemical decontamination of primary loop																	
Cutting, chemicals in, chemicals out, cleanup/ decontamination								Type; Size; Ops; Interim Time; Decom Opt; Store Time	Type; Size; Ops; Interim Time; Decom Opt; Store Time	Type; Size; Decom Opt	Type; Size; Ops; Interim Time; Decom Opt; Store Time						

"X" indicates that none of the variables change the analysis.

Table E-5. (contd)

Activities	Issues																
	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
7. Large component removal																	
Remove reactor vessel and internals intact or cut up	Env; Land Mass	X				Trans Prox	Trans Prox	Type; Size; Ops; Interim Time; Decom Opt; Store Time	Type, Size, Ops; Interim Time, Decom Opt; Store Time	Type; Size; Decom Opt	Type; Size; Ops; Interim Time; Decom Opt; Store Time; Trans Prox			Trans Prox			
Steam generator and other large components removed intact or cut up	Env; Land Mass					Trans Prox	Trans Prox	Type; Size, Ops; Interim Time; Decom Opt; Store Time	Type, Size, Ops; Interim Time; Decom Opt; Store Time	Type, Size; Decom Opt	Type; Size; Ops; Interim Time; Decom Opt; Store Time; Trans Prox			Trans Prox			

"X" indicates that none of the variables change the analysis

Table E-5. (contd)

Activities	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
	Issues																
8. Storage preparation activities for SAFSTOR																	
Establish a reactor coolant system vent pathway				Gas Emissions				Type; Size; Ops; Interim Time; Store Time		Type; Size; Ops; Interim Time; Store Time	Type; Size; Ops; Interim Time; Store Time						
Establish containment vent pathway				Gas Emissions				Type; Size; Ops; Interim Time; Store Time		Type; Size; Ops; Interim Time; Store Time	Type; Size; Ops; Interim Time; Store Time						
De-energize systems, put in monitors where they are needed								Type; Size; Ops; Interim Time; Store Time		Type; Size	Type; Size; Ops; Interim Time; Store Time						

"X" indicates that none of the variables change the analysis.

Table E-5. (contd)

Activities	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
	Issues																
Perform a radiological asessment								Type; Size; Ops; Interim Time; Store Time			Type; Size; Ops; Interim Time; Store Time						
9. Storage (SAFSTOR)																	
Monitor systems and radiation levels, etc.								Type; Size, Interim Time; Store Time		Type, Size; Store Time	Type, Size; Store Time						
Do preventive and corrective maintenance on SSCs								Type; Size, Interim Time; Store Time			Type; Size; Store Time						
Maintain the security system											Store Time; Multi-Unit						

"X" indicates that none of the variables change the analysis.

Table E-5. (contd)

Activities	Issues: Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
Maintain effluent and environmental monitoring programs				Gas Emissions							Store Time; Multi-Unit						
10. Decontamination and Dismantlement phases of DECON, SAFSTOR, and ENTOMB1																	
Chemical decontamination (surface/specific components)								Type; Size; Ops, Interim Time; Store Time	Type; Size; Ops; Interim Time; Store Time	Type; Size	Type; Size; Ops; Interim Time; Store Time						
Decontamination of piping inside walls								Type; Size; Ops; Interim Time; Store Time	Type; Size; Ops; Interim Time; Store Time	Type; Size	Type; Size; Ops; Interim Time; Store Time						
High-pressure water sprays of surface		X	X					Type; Size; Ops; Interim Time; Store Time	Type; Size; Ops; Interim Time; Store Time		Type; Size; Ops; Interim Time; Store Time						

"X" indicates that none of the variables change the analysis.

Table E-5. (contd)

Activities	Issues																
	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
Remove contaminated soil from specific areas						Loc; Env, Land Mass	Loc; Env; Land Mass	Type; Size; Ops; Interim Time; Store Time		Type; Size	Type; Size; Ops; Interim Time; Store Time			Loc; Land Mass			
Do preventive and corrective maintenance on SSCs								Type; Size; Ops; Interim Time; Store Time		Type, Size	Type; Size; Ops; Interim Time; Store Time						
Maintain the security system											Type; Multi-Unit						
Maintain effluent and environmental monitoring programs				Gas Emissions							Type; Multi-Unit						

"X" indicates that none of the variables change the analysis.

Table E-5. (contd)

Activities	Issues																
	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
11. System dismantlement																	
Cut out radioactive piping								Type; Size; Ops; Interim Time; Decom Opt; Store Time; Struct	Type; Size; Ops; Interim Time; Decom Opt; Store Time; Struct	Type; Size; Ops; Interim Time; Decom Opt; Store Time; Struct	Type; Size; Ops; Interim Time; Decom Opt; Store Time; Struct						
Remove large and small tanks or other radioactive components from the facility								Type; Size; Ops; Interim Time; Decom Opt; Store Time; Struct	Type; Size; Ops; Interim Time; Decom Opt; Store Time; Struct	Type; Size; Ops; Interim Time; Decom Opt; Store Time; Struct	Type; Size; Ops; Interim Time; Decom Opt; Store Time; Struct						

"X" indicates that none of the variables change the analysis.

Table E-5. (contd)

Activities	Issues: Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
12. Structure Dismantlement																	
Rubblization	Size	Size	Grd-water	Size; Loc; Land Mass				Type; Size; Loc; Ops; Interim Time; Decom Opt; Store Time		X	Size				X	X	X
Remove structures that are necessary for plant operation	Size; Loc; Land Mass	Size; Struct		Type, Size; Struct	Size; Loc	Size, Loc	Size, Loc	Type; Size; Loc; Ops; Interim Time, Decom Opt; Store Time	Type; Size; Loc; Ops; Interim Time; Decom Opt; Store Time	Size; Decom Opt; Land Mass	Type; Size, Loc; Ops; Interim Time, Decom Opt; Store Time				Size, Loc	Size; Loc	Size; Decom Opt
"X" indicates that none of the variables change the analysis.																	

Table E-5. (contd)

Activities	Issues																
	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
13. Entombment																	
Install engineered barriers				Size				Size		X	Size				X	X	
Disconnect operational systems (e g., electrical and fire protection)								Size		X	Size						
Remove all radioactive material that is outside of containment								Type; Size		X	Type; Size					Type; Size; Land Mass	
Place material inside containment										X	Size						
Lower containment ceiling (optional)		X		Type; Size				Type; Size; Ops; Interim Time	Type; Size; Ops; Interim Time	X	Size						
ENTOMB facility in concrete		X		Type; Size				Type; Size; Ops; Interim Time		X	Size				X	X	
"X" indicates that none of the variables change the analysis.																	

Table E-5. (contd)

Activities	Issues																
	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
14. LLW packaging and storage and disposal	X							Type; Size; Ops; Interim Time; Decom Opt; Store Time	Type; Size; Ops; Interim Time; Decom Opt; Store Time	Type, Size; Ops; Interim Time; Decom Opt, Store Time	Type; Size; Ops, Interim Time; Decom Opt; Store Time						Type; Size; Ops; Interim Time; Decom Opt; Store Time
15. Transportation																	
Large components				Size; Loc; Env; Decom Opt				LLW; Trans Prox	LLW; Trans Prox	X	LLW; Trans Prox		LLW; Trans Prox				X
LLW				Trans Prox; Size; Loc; Env; Decom Opt; LLW				LLW	LLW	X	LLW		Size; Loc; Env				X

"X" indicates that none of the variables change the analysis.

Table E-5. (contd)

Activities	Issues																
	Onsite/Offsite Land Use	Water Use	Water Quality	Air Quality	Aquatic Ecology	Terrestrial Ecology	Threatened and Endangered Species	Radiological	Rad Accidents	Occ Issues	Cost	Socioeconomic	Env Justice	Cultural Impacts	Aesthetic Issues	Noise	Irretrievable Resources
Equipment into site				Decom Opt; Trans Prox							Trans Prox						
Backfill trucked into site				Size; Decom Opt							Size; Decom Opt; Land Mass; Trans Prox						X
Nonradioactive waste				Size; Loc; Env; Struct; Decom Opt, Trans Prox							Type; Size; Decom Opt						X

Table E-5. (contd)

16. License Termination Activities																	
Complete final radiation survey								X		X	Size; Type; Decom Opt; Land Mass						
Partial site release								X			Loc; Env; Struct, Land Mass; Culture						

"X" indicates that none of the variables change the analysis.

Appendix F

Summary Table of Permanently Shutdown and Currently Operating Commercial Nuclear Reactors

Table F-1. Permanently Shutdown Commercial Nuclear Plants

Nuclear Plant	Location	Reactor Type	Thermal Power	Decommissioning Option[a]	Total Site Area (ac)	Cooling System[b]	Cooling Water Source	Fuel Location	Operating License	Shutdown Date[c]
Reactors that are Currently in the Process of Decommissioning										
Big Rock Point	Michigan	BWR	240 MW	DECON	593	OT	Lake Michigan	Fuel in pool	05/01/1964	08/30/1997
Dresden, Unit 1	Illinois	BWR	700 MW	SAFSTOR	953+1274 cooling pond	Cooling lake and spray system	Kankakee River	Fuel in onsite ISFSI	09/28/1959	10/31/1978
Fermi, Unit 1	Michigan	FBR	200 MW	SAFSTOR	900[d]	OT	Lake Erie	No fuel onsite	05/01/1963	09/22/1972
GE-VBWR	California	BWR	50 MW	SAFSTOR	~1[e]	MDCI	Onsite cooling pond	No fuel onsite	05/14/1956	12/09/1963
Haddam Neck	Connecticut	PWR	1825 MW	DECON	524	OT	Connecticut River	Fuel in pool	12/27/1974	07/22/1996
Humboldt Bay, Unit 3	California	BWR	200 MW	SAFSTOR	143	OT	Humboldt Bay	Fuel in pool	08/28/1962	07/02/1976
Indian Point, Unit 1	New York	PWR	615 MW	SAFSTOR	239	OT	Hudson River	Fuel in pool	03/26/1962	10/31/1974
La Crosse	Wisconsin	BWR	165 MW	SAFSTOR	163[f]	FCDC	Mississippi River	Fuel in pool	07/03/1967	04/30/1987
Maine Yankee	Maine	PWR	2700 MW	DECON	820	OT	Montsweag Bay	Fuel in pool	06/29/1973	12/06/1996
Millstone, Unit 1	Connecticut	BWR	2011 MW	SAFSTOR	500	OT	Long Island Sound	Fuel in pool	10/07/1970	11/04/1995
Peach Bottom, Unit 1	Pennsylvania	HTGR	115 MW	SAFSTOR	620[g]	OT	NA	No fuel onsite	06/01/1967	10/31/1974

Table F-1. (contd)

Nuclear Plant	Location	Reactor Type	Thermal Power	Decommissioning Option[a]	Total Site Area (ac)	Cooling System[b]	Cooling Water Source	Fuel Location	Operating License	Shutdown Date[c]
Reactors that are Currently in the Process of Decommissioning (contd)										
Rancho Seco	California	PWR	2772 MW	SAFSTOR/ incremental decom	2480	NDCT	Folsom Canal	Fuel in onsite ISFSI/ DECON proposed in 1997	08/16/1974	06/07/1989
San Onofre, Unit 1	California	PWR	1347 MW	SAFSTOR	84	OT	Pacific Ocean	Fuel in pool	03/27/1967	11/30/1992
Saxton	Pennsylvania	PWR	28 MW	SAFSTOR	~1.1[h]	OT[i]	Juniata River	No fuel onsite/ currently in DECON	11/15/1961	05/01/1972
Three Mile Island, Unit 2	Pennsylvania	PWR	2772 MW	Accident cleanup followed by storage	472	NDCT	Susquehanna River	Approx 900 kg fuel onsite/ Post-Defueling Monitored Storage	02/08/1978	03/28/1979
Trojan	Oregon	PWR	3411 MW	DECON	635	NDCT	Columbia River	Fuel in pool	11/21/1975	11/09/1992
Yankee Rowe	Massachusetts	PWR	600 MW	DECON	1997	OT	Deerfield River	Fuel in pool[j]	12/24/1963	10/01/1991
Zion, Unit 1	Illinois	PWR	3250 MW	SAFSTOR	250	OT	Lake Michigan	Fuel in pool	10/19/1973	02/21/1997
Zion, Unit 2	Illinois	PWR	3250 MW	SAFSTOR	250	OT	Lake Michigan	Fuel in pool	11/14/1973	09/19/1996

Table F-1. (contd)

Nuclear Plant	Location	Reactor Type	Thermal Power	Decommissioning Option[(a)]	Total Site Area (ac)	Cooling System[(b)]	Cooling Water Source	Fuel Location	Operating License	Shutdown Date[(c)]
Reactors that have had their Licenses Terminated										
Fort St. Vrain	Colorado	HTGR	842 MW	DECON	2798	OT	NA	Fuel in ISFSI/ License terminated in 1997	12/01/1976	08/18/19891
Pathfinder	South Dakota	BWR	190 MW	SAFSTOR	1200	MDCT	Big Sioux River	No fuel onsite/ License terminated in 1992	01/01/1964	09/16/1967
Shoreham	New York	BWR	2436 MW	DECON	499	OT	Long Island Sound	No fuel onsite/ License terminated in 1995	06/01/1985	06/28/1989

(a) The option shown in the table for each plant is the option that has been officially provided to NRC. Plants in DECON may have had a short (1 to 4 yr) SAFSTOR period. Likewise, plants in SAFSTOR may have performed some DECON activities or may have transitioned from the storage phase into the decontamination and dismantlement phase of SAFSTOR.
(b) OT = once through; NDCT = natural draft cooling tower; FCDC = forced-circulation, direct cycle; MDCT - Mechanical Draft Cooling Tower; NA = not applicable.
(c) The shutdown date corresponds to the date of the last criticality.
(d) Originally licensed site area for Fermi, Unit 1. Currently, the facility occupies an area of less than 1.6 ha (4 ac) on the Fermi, Unit 2, site.
(e) The reactor building and associated structures occupy approximately 0 4 ha (1 ac) in the approximately 640 ha (1600 ac) Vallicitos Nuclear Center.
(f) The La Crosse site area is approximately 1 2 ha (3 ac) with the total utility-owned area being 66 ha (163 ac).
(g) Peach Bottom site area includes all units (1, 2, and 3).
(h) Originally licensed site area for the Saxton Plant was 0.4 ha (1.1 ac), wholly contained in a utility-owned property of approximately 61 ha (150 ac).
(i) Once-through cooling combined with a fossil steam electric generating facility also using spray pond during periods of high ambient temperatures.
(j) License is in process of transferring fuel to dry storage in onsite ISFSI.

Table F-2. Currently Operating Commercial Nuclear Plants

Nuclear Plant	Unit	Location	Reactor Type	Thermal Power[a]	Total Site Area, acres	Cooling System[b]	Cooling Water Source	Operating License	License Expiration[c]
Arkansas Nuclear One	1	Arkansas	PWR	2568 MW	1160	OT	Dardanelle Reservoir	05/21/1974	05/20/2034[d]
Arkansas Nuclear One	2	Arkansas	PWR	2815 MW	1160	NDCT	Dardanelle Reservoir	09/01/1978	07/17/2018
Beaver Valley	1	Pennsylvania	PWR	2652 MW	501	NDCT	Ohio River	07/02/1976	01/29/2016
Beaver Valley	2	Pennsylvania	PWR	2652 MW	501	NDCT	Ohio River	08/14/1987	05/27/2027
Braidwood	1	Illinois	PWR	3411 MW	4457	CCCP	Kankakee River	07/02/1987	10/17/2026
Braidwood	2	Illinois	PWR	3411 MW	4457	CCCP	Kankakee River	05/20/1988	12/18/2027
Browns Ferry	1	Alabama	BWR	3293 MW	840	OT with towers	Tennessee River	12/20/1973	12/20/2013
Browns Ferry	2	Alabama	BWR	3293 MW	840	OT with towers	Tennessee River	08/02/1974	06/28/2014
Browns Ferry	3	Alabama	BWR	3293 MW	840	OT with towers	Tennessee River	08/18/1976	07/02/2016
Brunswick	1	North Carolina	BWR	2558 MW	1210	OT	Cape Fear River	11/12/1976	09/08/2016
Brunswick	2	North Carolina	BWR	2436 MW	1210	OT	Cape Fear River	12/27/1974	12/27/2014
Byron	1	Illinois	PWR	3411 MW	1398	NDCT	Rock River	02/14/1985	10/31/2024
Byron	2	Illinois	PWR	3411 MW	1398	NDCT	Rock River	01/30/1987	11/06/2026
Callaway		Missouri	PWR	3565 MW	3188	NDCT	Missouri River	10/18/1984	10/18/2024
Calvert Cliffs	1	Maryland	PWR	2700 MW	1135	OT	Chesapeake Bay	07/31/1974	07/31/2034[d]
Calvert Cliffs	2	Maryland	PWR	2700 MW	1135	OT	Chesapeake Bay	11/30/1976	08/31/2036[d]
Catawba	1	South Carolina	PWR	3411 MW	391	MDCT	Lake Wylie	01/17/1985	12/06/2024
Catawba	2	South Carolina	PWR	3411 MW	391	MDCT	Lake Wylie	05/15/1986	02/24/2026
Clinton		Illinois	BWR	2894 MW	14090	OT	Salt Creek	04/17/1987	09/29/2026
Columbia Generating Station		Washington	BWR	3486 MW	DOE, Hanford Reservation	MDCT	Columbia River	04/13/1984	12/20/2023
Comanche Peak	1	Texas	PWR	3411 MW	7669	OT	Squaw Creek Reservoir	04/17/1990	02/08/2030
Comanche Peak	2	Texas	PWR	3411 MW	7669	OT	Squaw Creek Reservoir	04/06/1993	02/02/2033
Cooper		Nebraska	BWR	2381 MW	1090	OT	Missouri River	01/18/1974	01/18/2014
Crystal River	3	Florida	PWR	2544 MW	4738	OT	Gulf of Mexico	01/28/1977	12/03/2016
Davis Besse		Ohio	PWR	2772 MW	954	NDCT	Lake Erie	04/22/1977	04/22/2017
Diablo Canyon	1	California	PWR	3338 MW	741	OT	Pacific Ocean	11/02/1984	09/22/2021
Diablo Canyon	2	California	PWR	3411 MW	741	OT	Pacific Ocean	08/26/1985	04/26/2025
Donald C. Cook	1	Michigan	PWR	3250 MW	642	OT	Lake Michigan	10/25/1974	10/25/2014
Donald C. Cook	2	Michigan	PWR	3411 MW	642	OT	Lake Michigan	12/23/1977	12/23/2017
Dresden	2	Illinois	BWR	2527 MW	953+1274 Cooling pond	Cooling lake and spray canal	Kankakee	02/20/1991	01/10/2006
Dresden	3	Illinois	BWR	2527 MW	953+1274 Cooling pond	Cooling lake and spray canal	Kankakee	03/02/1971	01/12/2011
Edwin I Hatch	1	Georgia	BWR	2558 MW	2244	MDCT	Altamaha River	10/13/1974	08/06/2034
Edwin I Hatch	2	Georgia	BWR	2558 MW	2244	MDCT	Altamaha River	06/13/1978	06/13/2038
Fermi	2	Michigan	BWR	3430 MW	1120	NDCT	Lake Erie	07/15/1985	03/20/2025
Fort Calhoun	1	Nebraska	PWR	1500 MW	667	OT	Missouri River	08/09/1973	08/09/2013
Ginna	1	New York	PWR	1520 MW	338	OT	Lake Ontario	12/10/1984	09/18/2009
Grand Gulf	1	Mississippi	BWR	3833 MW	2100	NDCT	Mississippi River	11/01/1984	06/16/2022

Table F-2. (contd)

Nuclear Plant	Unit	Location	Reactor Type	Thermal Power[a]	Total Site Area, acres	Cooling System[b]	Cooling Water Source	Operating License	License Expiration[c]
H B. Robinson	2	South Carolina	PWR	2300 MW	4942	OT	Lake Robinson	09/23/1970	07/31/2010
Hope Creek	1	Delaware	BWR	3293 MW	740	NDCT	Delaware River	07/25/1986	04/11/2026
Indian Point	2	New York	PWR	3071 MW	239	OT	Hudson River	09/28/1973	09/28/2013
Indian Point	3	New York	PWR	3025 MW	239	OT	Hudson River	04/05/1976	12/15/2015
James A. Fitzpatrick		New York	BWR	2536 MW	702	OT	Lake Ontario	10/17/1974	10/17/2014
Joseph M. Farley	1	Alabama	PWR	2775 MW	1850	MDCT	Chattahochee River	06/25/1977	06/25/2017
Joseph M. Farley	2	Alabama	PWR	2775 MW	1850	MDCT	Chattahochee River	03/31/1981	03/31/2021
Kewaunee		Wisconsin	PWR	1650 MW	908	OT	Lake Michigan	12/21/1973	12/21/2013
La Salle	1	Illinois	BWR	3323 MW	3064	Cooling pond	Illinois River	08/13/1982	05/17/2022
La Salle	2	Illinois	BWR	3323 MW	3064	Cooling pond	Illinois River	03/23/1984	12/16/2023
Limerick	1	Pennsylvania	BWR	3458 MW	595	NDCT	Schuylkill River	08/08/1985	10/26/2024
Limerick	2	Pennsylvania	BWR	3458 MW	595	NDCT	Schuylkill River	08/25/1989	06/22/2029
McGuire	1	North Carolina	PWR	3411 MW	577	OT	Lake Norman	07/08/1981	06/12/2021
McGuire	2	North Carolina	PWR	3411 MW	577	OT	Lake Norman	05/27/1983	03/03/2023
Millstone	2	Connecticut	PWR	2700 MW	494	OT	Long Island Sound	09/26/1975	07/31/2015
Millstone	3	Connecticut	PWR	3411 MW	494	OT	Long Island Sound	01/31/1986	11/25/2025
Monticello		Minnesota	BWR	1670 MW	2125	OT with towers	Mississippi River	01/09/1981	09/08/2010
Nine Mile Point	1	New York	BWR	1850 MW	890	OT	Lake Ontario	12/26/1974	08/22/2009
Nine Mile Point	2	New York	BWR	3467 MW	890	NDCT	Lake Ontario	07/02/1987	10/31/2026
North Anna	1	Virginia	PWR	2893 MW	1043	OT	Lake Anna	04/01/1978	04/01/2018
North Anna	2	Virginia	PWR	2893 MW	1043	OT	Lake Anna	08/21/1980	08/21/2020
Oconee	1	South Carolina	PWR	2568 MW	519	OT	Lake Keowee	02/06/1973	02/06/2033[d]
Oconee	2	South Carolina	PWR	2568 MW	519	OT	Lake Keowee	10/06/1973	10/06/2033[d]
Oconee	3	South Carolina	PWR	2568 MW	519	OT	Lake Keowee	07/19/1974	07/19/2034[d]
Oyster Creek	1	New Jersey	BWR	1930 MW	1416	OT	Barnegat Bay	04/09/1969	12/15/2009
Palisades	1	Michigan	PWR	2530 MW	487	MDCT	Lake Michigan	03/24/1971	03/14/2007
Palo Verde	1	Arizona	PWR	3800 MW	4050	MDCT	Phoenix City Sewage and Treatment Plant	06/01/1985	12/31/2024
Palo Verde	2	Arizona	PWR	3876 MW	4050	MDCT	Phoenix City Sewage and Treatment Plant	04/24/1986	12/09/2025
Palo Verde	3	Arizona	PWR	3876 MW	4050	MDCT	Phoenix City Sewage and Treatment Plant	11/25/1987	03/25/2027
Peach Bottom	2	Pennsylvania	BWR	3458 MW	620	OT with towers	Conowingo Pond	12/14/1973	08/08/2013
Peach Bottom	3	Pennsylvania	BWR	3458 MW	620	OT with towers	Conowingo Pond	07/02/1974	07/02/2014
Perry	1	Ohio	BWR	3579 MW	1112	NDCT	Lake Erie	11/13/1986	03/18/2026
Pilgrim	1	Massachusetts	BWR	1998 MW	517	OT	Cape Cod Bay	09/15/1972	06/08/2012
Point Beach	1	Wisconsin	PWR	1519 MW	2065	OT	Lake Michigan	10/05/1970	10/05/2010
Point Beach	2	Wisconsin	PWR	1519 MW	2065	OT	Lake Michigan	03/08/1973	03/08/2013
Prairie Island	1	Minnesota	PWR	1650 MW	568	MDCT or OT	Mississippi River	04/05/1974	08/09/2013
Prairie Island	2	Minnesota	PWR	1650 MW	568	MDCT or OT	Mississippi River	10/29/1974	10/29/2014

Table F-2. (contd)

Nuclear Plant	Unit	Location	Reactor Type	Thermal Power[a]	Total Site Area, acres	Cooling System[b]	Cooling Water Source	Operating License	License Expiration[c]
Quad Cities	1	Illinois	BWR	2511 MW	784	OT	Mississippi River	12/14/1972	12/14/2012
Quad Cities	2	Illinois	BWR	2511 MW	784	OT	Mississippi River	12/14/1972	12/14/2012
River Bend	1	Louisiana	BWR	2894 MW	3342	MDCT	Mississippi River	11/20/1985	08/29/2025
Salem	1	New Jersey	PWR	3411 MW	691	OT	Delaware River	12/01/1976	08/13/2016
Salem	2	New Jersey	PWR	3411 MW	691	OT	Delaware River	05/20/1981	04/18/2020
San Onofre	2	California	PWR	3390 MW	84	OT	Pacific Ocean	09/07/1982	10/18/2013
San Onofre	3	California	PWR	3390 MW	84	OT	Pacific Ocean	09/16/1983	10/18/2013
Seabrook	1	New Hampshire	PWR	3411 MW	896	OT	Atlantic Ocean	03/15/1990	10/17/2026
Sequoyah	1	Tennessee	PWR	3411 MW	525	OT and/or NDCT	Chickamauga Lake	09/17/1980	09/17/2020
Sequoyah	2	Tennessee	PWR	3411 MW	525	OT and/or NDCT	Chickamauga Lake	09/15/1981	09/15/2021
Shearon Harris	1	North Carolina	PWR	2775 MW	10744	NDCT	Buckhorn Creek	01/12/1987	10/24/2026
South Texas	1	Texas	PWR	3800 MW	12350	CCCP	Colorado River	03/22/1988	08/20/2027
South Texas	2	Texas	PWR	3800 MW	12350	CCCP	Colorado River	03/28/1989	12/15/2028
St. Lucie	1	Florida	PWR	2700 MW	1132	OT	Atlantic Ocean	03/01/1976	03/01/2016
St. Lucie	2	Florida	PWR	2700 MW	1132	OT	Atlantic Ocean	06/10/1983	04/06/2023
Summer	1	South Carolina	PWR	2900 MW	2200	OT	Lake Monticello	11/12/1982	08/06/2022
Surry	1	Virginia	PWR	2546 MW	840	OT	James River	05/25/1972	05/25/2012
Surry	2	Virginia	PWR	2546 MW	840	OT	James River	01/29/1973	01/29/2013
Susquehanna	1	Pennsylvania	BWR	3441 MW	1075	NDCT	Susquehanna River	11/12/1982	07/17/2022
Susquehanna	2	Pennsylvania	BWR	3441 MW	1075	NDCT	Susquehanna River	06/27/1984	03/23/2024
Three Mile Island	1	Pennsylvania	PWR	2568 MW	472	NDCT	Susquehanna River	04/19/1974	04/19/2014
Turkey Point	3	Florida	PWR	2300 MW	23970	Closed cycle canal	Biscane Bay	07/19/1972	07/19/2032
Turkey Point	4	Florida	PWR	2300 MW	23970	Closed cycle canal	Biscane Bay	04/10/1973	04/10/2033
Vermont Yankee	1	Vermont	BWR	1593 MW	125	OT and towers	Connecticut River	02/28/1973	03/21/2012
Vogtle	1	Georgia	PWR	3565 MW	3169	NDCT	Savannah River	03/16/1987	01/16/2027
Vogtle	2	Georgia	PWR	3565 MW	3169	NDCT	Savannah River	03/31/1989	02/09/2029
Waterford	3	Louisiana	PWR	3390 MW	3561	OT	Mississippi	03/16/1985	12/18/2024
Watts Bar	1	Tennessee	PWR	3411 MW	1769	NDCT	Chickamauga Lake	02/07/1996	11/09/2035
Wolf Creek	1	Kansas	PWR	3565 MW	9818	CCCP	Wolf Creek	06/04/1985	03/11/2025

(a) Licensees may seek power uprates
(b) OT = once-through, NDCT = natural draft cooling towers; CCCP = closed-cycle cooling pond, MDCT = mechanical draft cooling towers.
(c) Licensees may seek a renewal of the license
(d) Includes 20-year license renewal period

Appendix G

Radiation Protection Considerations for Nuclear Power Facility Decommissioning

Appendix G

Radiation Protection Considerations for Nuclear Power Facility Decommissioning

Radiological issues are associated with the process of decommissioning nuclear reactor facilities, including power reactors, at the end of their operating lives. Both occupational workers and members of the public will be affected by these processes as a result of direct exposures to sources of radiation and as a result of small releases of radioactive materials in gaseous and liquid effluents. This appendix is intended to provide pertinent background information for analyses in this Generic Environmental Impact Statement Supplement.

G.1 Radiation Protection Standards

The primary U.S. Nuclear Regulatory Commission (NRC) standards for protection of workers and members of the public are found in 10 CFR Part 20. These standards are consistent with guidance to Federal agencies prepared by interagency committees and issued by the President. The Federal guidance is based on recommendations published by national and international organizations, such as the National Council on Radiation Protection and Measurements (NCRP), the International Commission on Radiological Protection (ICRP), and the United Nations Scientific Committee on the Effects of Atomic Radiation. Proposed changes to regulations are typically published in the Federal Register for public comment before enactment of the final rule. The most recent major revision to the NRC radiation protection regulations in 10 CFR Part 20 were enacted in 1991, with several amendments issued in the intervening years. Implementation of the regulations became mandatory for NRC licensees in 1994.

G.1.1 Concepts, Terminology, Quantities, and Units Used in Radiation Protection

Title 10 CFR Part 20 was first promulgated in 1957. In 1961, the regulation was amended to add an appendix containing maximum permissible concentrations and a new occupational dose limit structure for whole-body exposure to external radiation (1.25 rem/quarter, or 3 rem/quarter with 5 rem/yr average as a limit on the cumulative dose). The 1991 revision differs considerably from the previous regulations with respect to basic concepts, terminology, radiation dose quantities, and the associated dose units. This section is included to familiarize readers with these concepts.

G.1.1.1 Conventional Quantities and Units

In 10 CFR Part 20, the unit "rad" is usually used for the quantity "radiation absorbed dose" whenever early biological effects are the concern. When latent effects (e.g., cancer and genetic effects) are being considered, the unit "rem" is used for the dose equivalent (DE) quantity. The absorbed dose in rads is multiplied by an overall efficiency factor *Q* to obtain the DE in rem. Each type of radiation has its own value of *Q*, which in a very general way permits adding absorbed doses from different radiations to estimate the probability of stochastic effects. Values of Q in 10 CFR Part 20 are indicated in Table G-1.

Table G-1. Quality Factors and Absorbed Equivalents

Radiation	Absorbed Dose, rad	Q	Dose Equivalent, rem
x -, gamma or beta radiation	1	1	1
Alpha particles	1	20	20
Neutron (spectrum unknown)	1	10	10
Note: To convert rem to sievert, multiply by 0.01.			

These values of *Q* reflect the overall efficiency of a given type of radiation in causing latent effects and are not used for early effects such as acute radiation syndrome. The values were derived in consideration of the ability of the various radiations to ionize atoms in water as well as the relative biological effectiveness factors observed for specific effects.

G.1.1.2 International System of Units

The International System (SI) units of particular interest in radiation protection are the gray (Gy), sievert (Sv), and becquerel (Bq), as shown in Table G-2. The SI units are part of the metric system; however, they are not yet widely used in the United States.
Title 10 CFR 20.2101 requires the records to be reported in the units of curie, rad, and rem. The major concern of the NRC staff is that use of both the conventional and SI units would introduce confusion under emergency conditions.

Table G-2. Conventional and SI Units

Quantity	Conventional Unit	SI Unit	SI Unit Conversions
Absorbed dose	rad (100 ergs/gram)	gray (Gy) (10,000 ergs/gram)	100 rad = 1 Gy
Dose equivalent	rem (Q x rad)	sievert (Sv) (Q x gray)	100 rem = 1 Sv
Activity	curie (Ci) (3.7×10^{10} disintegrations per second)	becquerel (Bq) (1 disintegration per second)	1 Ci = $3.7 \times 10^{(10)}$ Bq

G.1.1.3 Collective Dose

Previous revisions of 10 CFR Part 20 made no use of the collective DE (in person-rem). However, this quantity is used by the NRC in risk analyses and in its decision-making processes. The collective DE may be obtained as the sum of all individual doses or as the product of the average individual dose and the number of people exposed. The linear-nonthreshold hypothesis is accepted by the NRC for purposes of standards setting. Such acceptance means that standards based on the hypothesis, coupled with the "as low as reasonably achievable" (ALARA) concept, are believed to provide an adequate degree of protection.

G.1.1.4 Risks from Radiation Exposure

The current regulations in 10 CFR Part 20 are based on concepts first developed by the ICRP in Publication 26 (ICRP 1977). The ICRP system is based on the recognition of two basic types of radiation-induced health effects: stochastic and nonstochastic. Stochastic effects, such as cancer and hereditary effects, are considered to be probabilistic in nature. For stochastic effects, the probability of the effect, but not the severity, is dose-dependent (i.e., once a malignancy occurs). Its severity is no different if the dose that preceded it were 1 Sv (100 rem), 0.1 Sv (10 rem), or zero. The objective of radiation protection policies is to control the probability of these effects to acceptable levels. In contrast, the severity of nonstochastic effects, but not the probability of occurrence, depends on the radiation dose. Examples of radiation-induced nonstochastic effects include cataracts in the lens of the eye or burns on the skin surface. Nonstochastic effects typically do not occur unless the dose exceeds a threshold, which is specific to each type of effect. Once the threshold dose is exceeded, the effect occurs, and the severity of the effect depends on the dose received by the affected tissue or organ. For example, a radiation-induced cataract caused by a 4-Sv (400-rem) dose to the lens of the

eye would impair vision to a greater extent than one following a dose of 1 Sv (100 rem). Therefore, radiation protection for nonstochastic effects is designed to keep radiological exposures to sensitive tissues below the threshold levels at which the effects would begin to appear.

In January 1990, the National Research Council (NAS 1990) published a report on the health effects of exposure to low levels of ionizing radiation. This report was prepared by the Committee on Biological Effects of Ionizing Radiation (BEIR) known as the BEIR-V Committee, organized by the Council for this purpose. The BEIR-V report concluded that the risk of radiation exposure was greater than estimates published by previous committees (NAS 1972, NAS 1980). In light of this data, the ICRP requested comment from a number of organizations on a draft of its revised recommendations on radiation protection. In 1991, the ICRP issued Publication 60 (ICRP 1991) recommending lower limits for occupational exposures. With regard to this Supplement, the primary importance of these developments lies in the selection of the most appropriate radiation risk coefficients to use for evaluating health effects. For a more complete history of the development of radiological risk estimates, see NRC (1996), Appendix E.

G.1.1.4.1 Stochastic Effects

Stochastic effects refer to health effects, such as cancer and inheritable genetic effects, for which the probability of occurrence is related to radiation dose. Based on the BEIR-V study (1990), the risks were estimated as 4 to 5 excess cancer deaths among 10,000 people receiving 100 person-Sv (10,000 person-rem). The following statement appears in the executive summary of the BEIR-V report (NAS 1990, p. 6):

> On the basis of the available evidence, the population-weighted average lifetime excess risk of death from cancer following an acute dose equivalent to all body organs of 0.1 Sv [0.1 Gy of low-linear energy transfer (LET) radiation] is estimated to be 0.8 percent, although the lifetime risk varies considerably with age at the time of exposure. For low-LET radiation, accumulation of the same dose over weeks or months, however, is expected to reduce the lifetime risk appreciably, possibly by a factor of 2 or more.

The 0.8-percent estimate is equivalent to 800 excess cancer fatalities among 100,000 people, each exposed to 0.1 Sv (10 rem). It is important to note that the risk values tabulated in the report are for a population size of 100,000 and that the 0.8-percent estimate is applicable to instantaneous, uniform irradiation of all organs. With regard to the lower extreme of the dose range over which the estimate is applicable, the Committee observes elsewhere in the BEIR-V report that "in general, the estimates of risk derived in this way for doses of less than 0.1 Gy (10 rem) are too small to be detectable by direct observation in epidemiological studies." The

report does not provide a risk estimate for instantaneous doses of fewer than 0.1 Sv (10 rem). The Committee's estimate is considered useful for estimating fatalities among large populations, including all ages, that are irradiated instantaneously and uniformly to individual external radiation doses of 0.1 Sv (10 rem) or more. Risk assessments based on the Japanese experience are subject to substantially greater uncertainty when applied to conditions typically encountered in environmental exposures from normal facility operations, where

- exposures are protracted
- the exposed population is small
- individual doses are much lower than 0.1Sv (10 rem)
- irradiation is caused by internally deposited radionuclides and is not uniform throughout the body
- the exposed population differs significantly from the atomic bomb survivor study group or
- some combination of these conditions exists.

For stochastic effects, the ICRP adopted the risk associated with 0.05 Sv (5 rem) in a year, delivered to every organ, as the basis for its dose-limitation system (ICRP 1977). Therefore, the stochastic annual limit on intake (ALI) for each radionuclide is the quantity that, if inhaled, would cause the same stochastic risk as a uniform, whole-body dose of 0.05 Sv (5 rem) delivered by external sources in 1 year. To establish these ALIs, the ICRP considered the possibility that a given radionuclide taken into the body eventually reaches the bloodstream and is then distributed selectively to the various organs and tissues, where DE is delivered over a time course determined by the retention capabilities of the organ or tissue and the physical characteristics of the radionuclide. Using a radiation risk coefficient specific for each organ or tissue and the 50-year integrated dose equivalent to the tissue, the risk associated with each is estimated. The total risk to the worker per quantity of this radionuclide inhaled is the sum of the individual organ or tissue risks. The intake that will produce the same overall stochastic risk as 0.05 Sv/yr (5 rem/yr) of uniform external radiation can then be readily calculated as the ALI. Of course, a worker may be exposed to several airborne radionuclides and to external radiation as well. In that case, the total risk is still limited to that associated with 0.05 Sv (5 rem) in a year from uniform external radiation. Compliance is achieved if the fraction of the external dose limit that is received, added to the fraction of ALI inhaled for each radionuclide, does not exceed unity.

The risk of hereditary effects is included in a special way that, in the view of the ICRP, renders it additive to the cancer fatality risk. The ICRP considered only detrimental effects that the worker is likely to experience personally, so that effects manifested after the second generation are not included in the genetic risk coefficient used. The coefficient is also limited to very serious genetic effects (i.e., those comparable in severity to premature death).

Although all organs and tissues receive the same DE under uniform exposure conditions, the cancer risks for a given dose in each organ are not the same. Each organ or tissue contributes to the overall risk based on the relative sensitivity of tissue to radiation-induced cancer. This fraction is called the weighting factor, and the sum of the weighting factors for all tissues is unity. The product of the weighting factor and the DE is the effective dose equivalent (EDE). This quantity is used for both external and internal irradiation and may be used for individual organs and tissues or for the sum of all organs and tissues. The unit used for either quantity is the same as for the DE, namely, the sievert (or rem). In the unique case of uniform irradiation of all organs and tissues, the sum of their EDEs is by definition equal to the whole-body DE. The EDE may be determined irrespective of the degree of uniformity among the organ or tissue doses. The sum of the EDEs is not allowed to exceed 0.05 Sv/yr (5 rem/yr).

The committed dose equivalent (CDE) is a quantity defined as the 50-year integrated DE to a specific organ or tissue following the inhalation of a radionuclide. This quantity is still used, but only in connection with nonstochastic effects. The committed effective dose equivalent (CEDE) is the same quantity as the CDE, with the exception that, in the case of the CEDE, each dose equivalent is multiplied by the tissue or organ weighting factor. The rem (or sievert) is also the unit for both of these quantities.

The mathematical weighting method used by the ICRP is shown in Table G-3. The first column lists the organs, and the second column lists the risk coefficients from ICRP Publication 26 (1977) and their sum, namely, 1.65×10^{-4}. This sum is the total annual risk to the exposed person, assuming exposure to these organs at 0.01 Gy/yr (1 rad/yr).[a] The fraction of this risk per rad for each organ can be obtained by dividing its risk coefficient by 1.65×10^{-4}. These fractions represent the relative sensitivity of the organs; they are the weighting factors and are designated by the symbol w_T, where T represents the organ or tissue. The weighting factors appear in column three of the table. If T is the dose equivalent to tissue T, then $w_T H_T$ is the

(a) Multiplication by 5 gives the annual risk at 0.05 Gy/yr (5 rad/yr) (i.e., 8.25×10^{-4}/yr). This risk value means that if groups of 10,000 workers were to receive the dose limit every year for their entire careers, data as of the mid-1970s indicate that an average of 8.25 fatal occupational radiation-induced cancers per year would occur within each group. Assuming the approximate worst case of 45 years of exposure, the toll theoretically would be about 370 deaths per group, or almost 4 percent.

weighted DE. For example, w_T for the lung is 0.12. If a weighted lung dose of H rem is set equal to a highly penetrating, uniform whole-body dose of 5 rem, then

$0.12\,H = 0.05$ Sv (5 rem) and
$H = 4.17$ Sv (41.7 rem).

By hypothesis and analogy, an annual DE of 0.417 Sv (41.7 rem) to only the lung would have the same effect as 0.05 Sv (5 rem) to all of the organs combined. For this reason, $w_T H_T$ is called the EDE.

Nonstochastic effects have thresholds, and they become more severe as the dose gets larger. The ICRP believes that none of the thresholds will be exceeded if the annual dose to any tissue or organ does not exceed 0.5 Gy (50 rad). This nonstochastic limit is reflected in Table G-3, where it is evident that nonstochastic effects are controlling for all but four organs that have the largest weighting factors, the most sensitive organs with respect to stochastic effects.

Table G-3. ICRP Publication 26 Risk Weighting System

Organs	Risk Coefficients, Effects per Organ-rem	Weighting Factors	Organ DE Causing Same Risk as 5 rem to Whole Body, rem	Annual DE Permitted, Exposure of One Organ, rem/yr
Gonads	4×10^{-5}	0.25	20	20
Breasts	2.5×10^{-5}	0.15	33-1/3	33-1/3
Lung	2×10^{-5}	0.12	41-2/3	41-2/3
Red marrow	2×10^{-5}	0.12	41-2/3	41-2/3
Bone	5×10^{-6}	0.03	166-2/3	50
Thyroid	5×10^{-6}	0.03	166-2/3	50
1st RO[a]	1×10^{-5}	0.06	83-1/3	50
2nd RO	1×10^{-5}	0.06	83-1/3	50
3rd RO	1×10^{-5}	0.06	83-1/3	50
4th RO	1×10^{-5}	0.06	83-1/3	50
5th RO	1×10^{-5}	0.06	83-1/3	50
Totals	1.65×10^{-4}	1.0		

(a) The remainder organs (ROs) are the five organs that receive, from a given radionuclide, the highest EDE, integrated over 50 years.
Note: To convert rem to sievert, multiply by 0.01.

G.1.1.4.2 Nonstochastic Effects

Nonstochastic effects refer to those, such as radiation-induced cataracts, for which the severity of the effect depends on radiation dose. They typically are not observed unless the radiation dose exceeds a minimum threshold, whereas the probability of stochastic effects is assumed to be greater than zero, although very small, even at very low doses. Therefore, radiological protection for nonstochastic effects is based on limiting exposures to levels that prevent the effect, rather than on controlling the probability of occurrence, as discussed previously for stochastic effects. For tissues such as the lens of the eye, the skin, and the extremities, radiation protection standards are intended primarily to control the dose from external sources. For internal organs, it is necessary to control the dose from internally deposited radionuclides as well. Because radiation can damage or kill cells if the dose is sufficiently high, a nonstochastic dose limit must be established for all tissues, including tissues other than those mentioned above.

ICRP Publication 41 (1983) provides the technical justification supporting the position that, with the exception of the lens of the eye, nonstochastic effects will not be observed among adults if the DE from external and internal radiation combined to every organ and tissue is less than 0.5 Sv/yr (50 rem/yr). The NRC is not aware of later radiobiological information indicating that this dose limit should be changed and notes that the ICRP retained this value in the 1990 revision of its recommendations (ICRP 1991).

G.1.1.4.3 Risk Coefficient Selection for This Supplement

The BEIR-V risk estimate can be arithmetically converted to the more familiar terminology of 8 cancer fatalities among 10,000 people exposed to 10 person-Sv (10,000 person-rem), leading to a convenient risk coefficient of 8×10^{-4} fatalities per person-rem. This coefficient is considered useful for estimating fatalities among large populations irradiated instantaneously and uniformly to individual external radiation doses of 0.1 Sv (10 rem) or more. However, since no dose or dose rate effectiveness factor (DDREF) is included in this risk factor, the fatality estimates become speculative as the individual doses and the size of the exposed population become progressively smaller. A DDREF of 2 has been recommended by the ICRP (1991) for doses below 0.2 Gy (20 rad) and dose rates below 0.1 Gy/h (10 rad/h), which corresponds to a risk coefficient 4.0×10^{-4} cancer fatalities per person-rem.

The risk coefficients for fatal cancer and hereditary effects (listed in Table G-4) are taken from ICRP (1991). The coefficients are consistent with the risk factors reported in BEIR-V if a DDREF of 2 is applied. The somewhat higher risk coefficients for the general population as compared to workers reflects the fact that individuals under age 18 at the time of exposure are more susceptible to radiation-induced cancer. A person must be 18 years or older to be

Table G-4. Nominal Probability Coefficients Used in this Supplement[(a)]

Health Effect	Occupational	Public
Fatal cancer	4	5
Hereditary	0.6	1

(a) Estimated number of excess effects among 10,000 people receiving 100 person-Sv (10,000 person-rem).

Source: ICRP Publication 60 (1991).

employed as a radiological worker. Excess hereditary effects are listed separately because radiation-induced effects of this type have not been observed in any human population, as opposed to excess malignancies that have been identified among people receiving instantaneous and near-uniform exposures of 0.1 Sv (10 rem) or more. As applied to low-level environmental and occupational exposures, risk factors for radiological health effects are subject to substantial uncertainty. The lower limit of the range for these risk coefficients is assumed to be zero because there may be biological mechanisms that can repair damage caused by radiation at low doses and/or dose rates.

G.1.2 Occupational Protection Standards

Occupational radiation protection standards have been in effect since 1947, and have generally been revised downward over the years, from 1.0 roentgen/wk (or about 50 roentgen/yr) in 1947 to the current 0.05 Sv/yr (5 rem/yr) total effective dose equivalent (TEDE). For an historical overview of development of these regulations, see NRC (1996), Appendix E. The current regulation implements the concept of TEDE, as developed by ICRP Publication 26 (1977). This methodology accounts for both exposure to radiation from external sources and intakes of radionuclides into the body in assessing compliance with the standards. Standards that were previously in effect applied only to external dose and did not account for dose from intakes of radionuclides by workers, which were assessed separately. In practice, radionuclide intakes account for a small fraction of the total dose received by workers at nuclear power facilities.

Historical dose data for nuclear power plant workers are presented in Section G.2. Table G-5 presents a summary of the occupational standards in the 1991 revision of 10 CFR Part 20. On an annual basis, the whole-body limit has decreased from 12 roentgen (3 roentgen per quarter) in 1957 (external radiation only) to 0.05-Sv (5-rem) TEDE (external plus internal).

Regulatory control over the intake of radioactive materials in the workplace has always been a complex issue. Beginning in 1991, the NRC adopted the method published by the ICRP in Publication 26 (ICRP 1977). Under the ICRP method, the dose to each significantly irradiated

organ is weighted according to its radiation sensitivity. The weighted doses are summed to produce an EDE that can be added to the dose from external sources.

The revised 10 CFR Part 20 provides additional flexibility for establishing more accurate dose controls. It allows the use of actual particle-size distribution and physiochemical characteristics of airborne particulates to define site-specific derived air concentration limits. With NRC approval, these modified concentration limits can be used in lieu of generic values provided in 10 CFR Part 20. Such adjustments result in more precise estimates that use actual exposure conditions, as compared to generic assumptions.

The 1991 revision to 10 CFR Part 20 codifies a requirement that licensees implement a program to maintain radiation doses ALARA. Compliance with the commitments is required through the licensing process in 10 CFR Part 50 and the technical specifications. Two Regulatory Guides have been issued to provide guidance on ALARA programs for nuclear power plants: one on ALARA philosophy in NRC Regulatory Guide 8.10, Rev. 1R (NRC 1977), and one on implementation in NRC Regulatory Guide 8.8, Rev. 3 (NRC 1978). Nuclear power plant licensees are required to maintain and implement adequate plant procedures that contain ALARA criteria. During plant licensing, applicants commit to implement ALARA programs consistent with Regulatory Guides 8.8 and 8.10.

Table G-5. Occupational Dose Limits for Adults in 10 CFR Part 20[a]

Tissue	External Radiation	Internal Plus External Radiation
Whole Body	0.05 Sv/y (5 rem/yr) total DE,[b] not to exceed 0.5 Sv/y (50 rem/yr) total DE to any individual organ or tissue other than the lens of the eye	0.05 Sv/yr (5 rem/year) TEDE,[c] not to exceed 0.5 Sv/yr (50 rem/yr) total DE to any individual organ or tissue other than the lens of the eye
Lens	0.15 Sv/yr (15 rem/yr)	
Extremities, Including Skin	0.5 Sv/yr (50 rem/yr)	
All Other Skin	0.5 Sv/yr (50 rem/yr)	

(a) These revised 10 CFR Part 20 standards became effective on January 1, 1994.
(b) The total DE is the sum of the EDE (at 1 cm [0.39 in] depth) and the CDE from nuclides deposited in the body.
(c) The TEDE is the sum of the EDE (at 1 cm depth [0.39 in]) and the CEDE from nuclides deposited in the body.

G.1.3 Public Radiation Protection Standards

For many years, the ICRP and NCRP recommended dose limits for the public that were 10 percent of those for workers. During the 1980s, both organizations adopted a more conservative value of 2 percent. In 1985, the ICRP released a statement that its principal limit for the whole body was 0.001 Sv/yr (0.1 rem/yr) EDE (ICRP 1985). However, a subsidiary limit of 0.005 Sv/yr (0.5 rem/yr) is authorized, provided that the average dose over a lifetime does not exceed 0.001 Sv/yr (0.1 rem/yr). The ICRP limit for the skin and lens of the eye is 0.05 Sv/yr (5 rem/yr). In 1987, the NCRP recommended limits of 0.001 Sv/yr (0.1 rem/yr) EDE for the whole body under conditions of continuous or frequent exposure and 0.005 Sv/yr (0.5/yr) for infrequent exposure (NCRP 1987). The NCRP limit for the lens of the eye, skin, and extremities is 0.05 Sv/yr (5 rem/yr).

The 1991 revision of 10 CFR Part 20 implements guidelines consistent with the recommended limit of 0.001 Sv/yr (0.1 rem/yr) EDE (see Table G-6). Provision is made for temporary increases to 0.005 Sv/yr (0.5 rem/yr) with prior authorization and justification. Hourly and annual dose rate limits for unrestricted areas are also included.

Licensees may also demonstrate compliance with the provisions of 10 CFR Part 20 by showing that annual average concentrations of radioactive material released in gaseous and liquid effluents at the boundary of an unrestricted area do not exceed the values specified in 10 CFR Part 20, Appendix B, Table 2.

Table G-6. Dose Limits for an Individual Member of the Public under 10 CFR Part 20[(a)]

Applicability by Pathway	Dose Limits
Annual dose, all pathways[(b)]	1 mSv/yr (0.1 rem/yr) TEDE[(c)]
External dose rate, unrestricted areas	0.02 mSv/h (0.002 rem/h) or 0.5 mSv/yr (0.05 rem/yr)
Temporary Annual Dose, all pathways[(d)]	5 mSv/yr (0.5 rem/yr) TEDE[(c)]
ALARA dose constraint, air emissions[(e)]	0.1 mSv/yr (0.01 rem/yr) TEDE[(c)]

(a) These revised 10 CFR Part 20 standards became effective on January 1, 1994.
(b) Excludes contribution from materials disposed to sanitary sewers.
(c) The TEDE is the sum of the EDE (at 1 cm depth) and the CEDE from nuclides deposited in the body.
(d) Temporary increases in the public dose limit are subject to prior authorization from the NRC and other constraints to ensure the increase is justified and controlled to be ALARA.
(e) This is not a 10 CFR Part 20 dose limit, but is given to ensure consistency with air emissions standards for Federal facilities in 40 CFR Part 61.

The NRC has not established standards for radiological exposures to biota other than humans on the basis that limits established for the maximally exposed members of the public would provide adequate protection for other species. In contrast to the regulatory approach applied to human exposures, the fate of individual nonhuman organisms is of less concern than the maintenance of the endemic population (NCRP 1991). Experience has shown that population stability is crucial to survival of most species. However, in many ecosystems individual members of a species may suffer relatively high mortality rates from natural causes without creating detrimental effects to the population as a whole. The exception might be for threatened or endangered species where protection of the individual may be required in order to avoid detrimental effects on a relatively small population.

Evaluations of radiation exposures to nonhuman biota at nuclear power facilities have not identified exposures that could be considered significant in terms of harm to the species, or which approach the public exposure limits in 10 CFR Part 20. Limiting exposure in humans to 1 mSv/yr (100 mrem/yr) will lead to dose rates to plants in animals in the same area of less than 1 mGy per day (100 mrad per day). The International Atomic Energy Agency (IAEA) concludes that there is no convincing evidence from scientific literature that chronic radiation dose rates below 1 mGy per day (100 mrad per day) will harm plant or animal populations (IAEA 1992). Because of the relatively lower sensitivity of nonhuman species to radiation, and the lack of evidence that nonhuman populations or ecosystems would experience detrimental effects at radiation levels found in the environment around nuclear power stations, effects on these biota are not evaluated in detail for the purposes of this Supplement.

In addition to the basic standards mentioned above, 10 CFR 50.36(a) contains license conditions that are imposed on licensees in the form of technical specifications applicable to effluents from nuclear power reactors. These specifications ensure that releases of radioactive materials to unrestricted areas during normal operations, including expected operational occurrences, remain ALARA. Appendix I to 10 CFR Part 50 provides numerical guidance on dose-design objectives and limiting conditions for operation for light-water reactors (LWRs) to meet the ALARA requirements. As a part of the licensing process, all licensees have provided reasonable assurance that the design objectives will be met for all unrestricted areas even during the decommissioning process. Title 10 CFR Part 20 requires compliance with the U.S. Environmental Protection Agency regulation 40 CFR Part 190, which also contains ALARA limits. The dose constraints are summarized in Tables G-7 and G-8.

Specific radiological criteria for license termination were added to 10 CFR Part 20 in 1997, and the basis for public health and safety considerations is discussed in NUREG-1496 (NRC 1997). These criteria limit the dose to members of the public to 0.25 mSv/yr (25 mrem/yr) from all

Table G-7. 10 CFR Part 50, Appendix I, Design Objectives and Annual Limits on Radiation Doses to the General Public from Nuclear Power Facilities[a]

Tissue	Gaseous	Liquid
Total body	0.05 mSv (5 mrem)	0.03 mSv (3 mrem)
Any organ, all pathways	--	0.01 mSv (10 mrem)
Ground-level air dose	0.1 mGy (10 mrad) gamma and 0.3 mGy (30 mrad) beta	--
		--
Any organ,[b] all pathways	0.15 mSv (15 mrem)	--
Skin	0.15 mSv (15 mrem)	

(a) Calculated doses.
(b) Particulates, radioiodines.

Table G-8. 40 CFR 190, Subpart B, Annual Limits on Doses to the General Public from Nuclear Power Operations[a]

Tissue	Limit	Source
Total body	0.25 mSv (25 mrem)	All effluents and direct radiation from nuclear power operations
Thyroid	0.75 mSv (75 mrem)	"
Any other organ	0.25 mSv (25 mrem)	"

(a) Calculated doses.

pathways following unrestricted release of a property. In cases where unrestricted release is not feasible, the licensee must provide for institutional controls that would limit the dose to members of the public to 0.25 mSv/yr (25 mrem/yr) during the control period and to 1 mSv/yr (100 mrem/yr) after the end of institutional controls. These criteria will largely determine the types and extent of activities undertaken during the decommissioning process to reduce the radionuclide inventory remaining onsite.

G.2 Nuclear Power Plant Exposure Data

G.2.1 Occupational Dose Experience

Individual occupational doses are measured by NRC licensees as required by the basic NRC radiation protection standard, 10 CFR Part 20. The exposure pathway of primary interest is from sources that are external to the body. Measurements of the whole-body dose are normally derived from personal dosimeters worn by each worker, and they represent a relatively uniform

dose to all organs of the body. Since 1984, many of the nuclear power plants have provided dosimetry programs accredited by the National Bureau of Standards (NBS, now National Institute of Standards and Technology [NIST]). In 1988, NBS/NIST accreditation became an NRC requirement.

Whole-body dose data from NRC-licensed LWRs are shown in Table G-9 for the years 1973 through 1999 (NRC 2000). For each year, the number of reactors, the number of workers receiving measurable exposures, the average annual dose per worker, the collective dose for all reactors combined, and the number of individuals exceeding 0.05 Sv (5 rem) are listed. Until 1991, the limit for exposure to workers was 0.03 Sv per quarter (3 rem per quarter), or a maximum of 0.12 Sv/yr (12 rem/yr), with an average of 0.05 Sv/yr (5 rem/yr). The collective dose is the sum of doses to workers at all plants. The collective doses to nuclear plant workers decreased from a peak of over 55 person-Sv/yr) (55,000 person-rem/yr) in 1983-1984 to less than 15 person-Sv/yr (15,000 person-rem/yr) in 1998-1999, although there are currently about 25 percent more operating plants than in the mid-1980s. Average annual doses to workers have likewise decreased from just under 0.01 Sv/yr (1 rem/yr) in the early 1970s to less than 0.25 mSv/yr (0.25 rem/yr) after 1997. Whole-body doses exceeding 0.05 Sv/yr (5 rem/yr) have been infrequent since 1985, and no doses at that level have been reported since 1989. Nuclear power plant workers may also be exposed to airborne radioactive material, primarily fission and corrosion products, but such exposures have historically been small in comparison with external doses. A study of intake data indicated that for cobalt-58 and cobalt-60, the most prevalent radionuclides, very few of the workers had organ burdens of more than 1 percent of the maximum permissible (see Baker 1996).

These data indicate that occupational exposures within the nuclear power industry have been significantly reduced since 1973. Individual doses are characteristically far below the regulatory limit, and the annual average is less than 5 percent of the 5 rem per year limit that is now in effect. Effective implementation of the ALARA concept is largely responsible. The range of risks associated with these exposures are discussed in Section G.1.

Occupational doses at reactors that are undergoing decommissioning are typically lower than those accumulated at operating facilities, as indicated in the Table G-9 data for reactors that are no longer operating. Between 1995 and 1999, the collective dose from shutdown facilities typically amounted to a few hundred person-rem per year, and the annual average dose per worker was comparable to, or lower than, that for operating facilities. A comparison in Table G-10 of the occupational doses at 12 facilities before and after they were shutdown confirms that decommissioning would not be expected to increase occupational doses on average, although some phases of the process may result in temporarily higher collective doses depending on the activities in progress and the number of workers involved.

Table G-9. Occupational Dose at Light Water Reactors (LWRs) - Comparison of Operating Reactors to Reactors No Longer in Operation[(a)]

Year	Number of Workers with Measurable Exposure[(b)]	Collective Dose, person-rem[(c)]	Average Dose per Worker with Measurable Exposure, rem[(c)]	Total Number with Dose > 5 rem[(d)]	Number of Reactors	Average Collective Dose per Reactor-Year, person-rem[(e)]
			Operating Reactors			
1973	14,780	13,962	0.945	--	24	582
1974	18,139	13,650	0.753	--	33	414
1975	28,234	20,901	0.740	--	44	475
1976	34,515	26,105	0.756	--	52	502
1977	38,985	32,521	0.834	351	57	571
1978	42,777	31,785	0.743	159	64	497
1979	60,299	39,908	0.662	180	67	596
1980	74,629	53,739	0.720	391	68	790
1981	76,772	54,163	0.706	210	70	774
1982	79,309	52,201	0.658	135	74	705
1983	79,709	56,484	0.709	169	75	753
1984	90,520	55,251	0.610	74	78	708
1985	86,926	43,048	0.495	1	82	525
1986	93,979	42,386	0.451	0	90	471
1987	96,231	40,406	0.420	0	96	421
1988	96,013	40,772	0.425	1	102	400
1989	100,084	35,931	0.359	0	107	336
1990	98,567	36,602	0.371	0	110	333
1991	91,086	28,519	0.313	0	111	257
1992	94,172	29,297	0.311	0	110	266
1993	86,193	26,364	0.306	0	108	244
1994	71,613	21,704	0.303	0	109	199
1995	70,821	21,688	0.306	0	109	199
1996	68,305	18,883	0.276	0	109	173
1997	68,372	17,149	0.251	0	109	157
1998	57,466	13,187	0.229	0	105	126
1999	59,216	13,666	0.231	0	104	131
Average 1973-1999	69,545	32,603	0.514	73		430
Average 1995-1999	64,836	16,915	0.259	0		157
			Permanently Shutdown Reactors[(f)]			
1995	699	262	0.375	0	6	44
1996	974	165	0.169	0	8	21
1997	1144	136	0.119	0	7	19
1998	2178	430	0.197	0	11	39
1999	2856	430	0.151	0	13	33
Average 1995-1999	1,570	285	0.202			31

(a) Data Source: NUREG-0713, Vol. 21 (NRC 2000)
(b) 1973-1976 data are not adjusted for multiple reporting of transient individuals
(c) To convert rem to sievert, multiply by 0.01.
(d) Number of workers by dose range not available for 1973-1976 The dose limit was 3 rem/quarter (12 rem/yr) before the 1991 revision of 10 CFR Part 20; thereafter, it was reduced to 5 rem/yr.
(e) To convert person-rem to person-sievert, multiply by 0 01.
(f) Includes plants not in operation for a full year as of December 31 of the reporting year.

Table G-10.

Occupational Whole-Body Dose at Decommissioning Reactors, Comparison of Dose During Operations to Dose During Decommissioning

						Average Annual Occupational Dose, person-rem/yr			Maximum Annual Occupational Dose, person-rem/yr		
Nuclear Plant	Reactor Type	Capacity, MWe	Years in Operation	Years Post Shutdown	D&D Method	Normal Power Operations	Post Shutdown	Post Shutdown as % of Operations	Operations	Post Shutdown	Post Shutdown as % of Operations
Ft. St. Vrain	HTGR[a]	330	10	12	DECON	3	106	4076.9	6	210	3500
Big Rock Point	BWR[b]	67	34	2	DECON	166	116	69.7	277	144	52.0
La Crosse	BWR	48	17	13	SAFSTOR	247	19	7.8	313	105	33.5
Humboldt Bay, Unit 3	BWR	63	13	25	SAFSTOR	294	183	62.4	339	1905	561.9
Yankee Rowe	PWR[c]	175	30	8	DECON	159	75	47	246	156	63.4
Haddam Neck	PWR	560	28	3	DECON	355	137	38.5	590	261	44.2
Maine Yankee	PWR	860	25	3	DECON	326	154	47.1	653	173	26.5
Trojan	PWR	1080	17	7	DECON	346	38	11	567	52	9.2
San Onofre, Unit 1	PWR	436	25	8	SAFSTOR	512	16	3.1	880	16	1.8
Rancho Seco	PWR	873	14	10	SAFSTOR	385	9	2.3	787	41	5.2
Zion, Units 1 and 2	PWRs	2080	24	2	DECON	645	8	1.2	1043	12	1.2
Average All LWR						343	75	29	570	287	79.9
Average BWR						235	106	46.6	310	718	215.8
Average PWR						390	62	21.5	681	102	21.6
Average DECON						333	88	35.8	563	133	32.7
Average SAFSTOR						359	57	18.9	580	517	150.6

(a) High-temperature gas-cooled reactor.
(b) Boiling water reactor.
(c) Pressurized water reactor.

Table G-11. Occupational Dose by Activity During Decommissioning

					Percent of Total Cumulative Dose to Completion by Activity					
Nuclear Plant	Reactor Type	Capacity, MWe	D&D Method	Cumulative Dose Post Shutdown, person-rem[a]	Large Component Removal, %	Systems, Structures, and Components Removal, %	Other Decon Activities, %	SNF Management, %	Transportation, %	SAFSTOR Activities, %
Fort St. Vrain	HTGR[b]	330	DECON	433	45.1	25.6	13.8		15.5	
Big Rock Point	BWR[c]	67	DECON	700						
Haddam Neck	PWR[d]	560	DECON	996	37	28.7	19.3	8.7	6.1	
Maine Yankee	PWR	860	DECON	946	9.9	12.8	74.2	3		
Trojan	PWR	1080	DECON	556	22.7	50.7	5.4	21.2		
Zion, Units 1 and 2	PWRs	2080	SAFSTOR	637						
Humboldt Bay, Unit 3	BWR	63	SAFSTOR	354			50.8		3.7	45.5
Rancho Seco	PWR	873	SAFSTOR	483	39.1	47.6	5.8			7.5
San Onofre, Unit 1	PWR	436	SAFSTOR	1100						
Average All Plants				689	26.9	28	36.9	8.3	8.4	18.1
Number of Plants				9	6	6	7	4	3	3
Occupational Dose in Decommissioning BWRs										
Average BWR				527			50.8		3.7	45.5
Number of Plants				2			1		1	1
BWR SAFSTOR				354			50.8		3.7	45.5
BWR DECON				700						
Occupational Dose in Decommissioning PWRs										
Average PWR				786	23.2	28.4	38.7	8.3	6.1	4.4
Number of Plants				6	5	5	5	4	1	2
PWR SAFSTOR				792	23.3	25	47.2	0.3		4.4
PWR DECON				784	23.2	30.8	33	11	6.1	

(a) Dose is estimated for activities during decommissioning at plants that have not reached license termination.
(b) High-temperature gas-cooled reactor.
(c) Boiling water reactor.
(d) Pressurized water reactor.

Table G-12. Reactor Vessel Removal Information and Data

Nuclear Plant	Total Bequerels (Curies) Removed	Personnel Exposure person-sievert (person-rem)	Segmented components/ Lineal inches cut	Cutting Methods	Considerations for Planning and Implementation
Haddam Neck (in progress)	2.8×10^{16} (750,000)	1.77 (177)	• Core baffle • Core former plates • Core barrel in active fuel region • Lower core support plate • Lineal inches cut - 23,251	• Abrasive water • MDM cutting	• Worker exposure • Airborne contamination • Waste form and disposal costs • Cavity cleanup requirements • Schedule
San Onofre, Unit 1 (in progress)	$1\ 2 \times 10^{16}$ (330,000)	0.73 (73)	• Core region of the core barrel • Core baffles/formers • Lower core support plates • Lineal inches cut - 10,821	• Abrasive water • MDM cutting	
Maine Yankee (in progress)	Not available	(actual to date) 0 24 (24)	• Upper guide structure • Upper core barrel • Core support barrel • Mid-core region • Thermal shield • Lineal inches cut - 14,000	• Abrasive water jet (AWJ) • Conventional machining	• Avoid thermal processing • Use AWJ and conventional machining vs. plasma arc and MDM/EDM to reduce the occupational dose • Modeled all the cuts in a 3D CAD system before actually performing any of the dismantlement • Segregating, capturing, and confining AWJ cutting waste • Solid waste collection system • Cavity water treatment system • Much Maine Yankee dismantlement done under water and remotely, which cut down the worker dose • Abrasive Feed Assist System (patent pending) • Underwater AWJ Vision Enhancement - remote operability (patent pending) • Minimized amount of secondary waste • For underwater equipment, a maintenance and reliability issue • Sequence of cuts (low to high activity) reduced occupational exposure
Big Rock Point (in progress)	Not available	Not available	N/A	N/A	

Table G-12. (contd)

Nuclear Plant	Total Bequerels (Curies) Removed	Personnel Exposure (person-rem)	Segmented components/ Lineal inches cut	Cutting Methods	Considerations for Planning and Implementation
Trojan (completed)	74,000 (2,000,000)[a]	0.72 (72)	N/A	N/A	• Used the fuel transfer crane to lift the reactor vessel and place in the container • Removed reactor vessel with internals intact • The internals were grouted in place with low-density cellular concrete • Placed the reactor vessel on a heavy haul trailer for road transport to the rail • Shipped the reactor vessel with internals to U.S. Ecology, Richland, WA • Eliminated 74,000 Bq (2 million curies) from the Trojan nuclear facility site

(a) The Trojan plant reactor vessel was removed and shipped intact to the disposal facility; reactor vessel internals were not removed as in the other plants listed in this table.

Tables G-11 and G-12 list available data regarding the distribution of the cumulative collective worker dose among the major types of activities that would occur during a typical decommissioning process. The lack of resolution in much of the data and the small number of facilities involved (10) precludes a detailed analysis. However, it appears that the largest share of occupational doses might be expected for three general classes of activities: (1) large component removal (reactor vessel, steam generators), (2) removal of other plant systems, structures, and components, and (3) the remaining general decontamination activities. Data for removal of the reactor vessel (Table G-12) indicate that the choice of removal method (i.e., intact or segmented) may influence the collective dose associated with the operation. Data for plants electing the SAFSTOR alternative were not substantially different from plants undergoing more immediate DECON. The one exception was at Humboldt Bay, where the plant was maintained in a shutdown condition over an extended period of time. In that case, SAFSTOR activities accounted for a relatively large fraction of the total estimated occupational dose. In all cases, the estimated cumulative doses through the end of decommissioning for these plants were within the estimates presented in the 1988 GEIS (NRC 1988).

G.2.2 Dose to Members of the Public

Doses to members of the public from power reactor effluents were summarized in a series of NRC reports entitled *Dose Commitments Due to Radioactive Releases from Nuclear Power Plant Sites*. The last volume published covers reactor operations during 1992 (NUREG/CR-2850, Baker 1996). Radioactive material is released in gaseous (airborne, and may contain particulates, such as radioiodine) and liquid (aqueous) effluents under stringently controlled conditions in accordance with technical specifications and NRC regulations. The term "dose commitment" indicates that the reported doses come from the inhalation and ingestion of radionuclides, as well as from external radiation from noble gases. The population dose caused by direct radiation from plant facilities is negligible. Table G-13 presents results obtained for the 18-year period ending in 1992. The public doses represent collective person-rem received by those who live within an 80-km (50-mi) radius of a site; data for individual sites also appear in this report. The population dose within 80 km (50 mi) of each plant is calculated for each operating reactor in the United States. The total collective dose is then obtained by combining the doses received by these populations. As with the occupational doses, collective dose to the public from reactor effluents has been decreasing steadily since the mid-1980s. The collective dose to members of the public is smaller by several orders of magnitude than the dose to plant workers.

Data on maximally exposed individuals from gaseous effluents is also reported annually to the NRC by each nuclear utility. Data for the period 1985-1987 were compiled in NUMARC (1989) and summarized in NRC (1996). A summary of the data is presented in Table G-14.

Inspection of this table reveals that the maximum doses to individuals via gaseous effluents are on the order of a few mrem per year, and the dose to an individual is orders of magnitude lower for most plants.

Table G-13. Summary of Collective Public and Occupational Doses for All Operating Nuclear Power Facilities Combined[a]

		Collective Public Dose, person-rem			
Year	**Number of Operating Reactors[b]**	**Liquid Effluents**	**Gaseous Effluents**	**Total**	**Average per reactor-yr, person-rem**
1975	44	76	1300	1300	30
1976	52	82	390	470	9.0
1977	57	160	540	700	12
1978	64	110	530	640	10
1979	67	220	1600	1800	27
1980	68	120	57	180	2.6
1981	70	87	63	150	2.1
1982	74	50	87	140	1.9
1983	75	95	76	170	2.3
1984	78	160	120	280	3.6
1985	82	91	110	200	2.4
1986	90	71	44	110	1.2
1987	96	56	22	78	0.81
1988	102	65	9.6	75	0.74
1989	107	68	16	84	0.79
1990	110	63	15	78	0.71
1991	111	70	17	88	0.79
1992	110	32	15	47	0.43

(a) Collective public dose calculated for those living within an 80-km (50-mi) radius of a nuclear plant site.
(b) Includes plants in operation at least 1 full year at the end of the reporting year.
Source: NUREG/CR-2850 (Baker 1996).
Note: To convert person-rem to person-sievert, multiply by 0.01.

Table G-14. Estimated Doses to the Maximally Exposed Individual from Routine Gaseous Effluents from Operating Facilities, mrem[a]

	1985	1986	1987
Average	2.8E-01	2.6E-01	9.1E-02
Minimum	7.8E-04	4.9E-04	1.0E-06
Maximum	1.8E+00	4.3E+00	8.9E-01
Number of plants reporting	26	33	34

(a) Data compiled from reports submitted to the NRC by each nuclear utility.
Adapted from NUMARC (1989).
Note: To convert millirem to millisievert, multiply by 0.01.

A comparison of more recent effluent release rates from both operating and decommissioning facilities (Table G-15) indicates that the gaseous release rates for many types of effluents are similar. Decommissioning facilities reported no emissions of radioiodine in their gaseous effluents, which would be as expected after the plants are shut down and defueled. Most of the iodine isotopes are short-lived and are not present in plants that have been out of operation for any length of time. Releases of longer-lived fission gases and particulate materials in gaseous effluents continue after the end of operation because of the need to maintain plant ventilation systems during activities associated with the decommissioning process. Radionuclide emissions in liquid effluents were typically lower in the shutdown facilities because the reactor core cooling systems were not operating, and the levels of radionuclides in circulating water systems needed to maintain the spent fuel pool are lower than in primary coolant for an operating plant.

Recent DEs to members of the public from emissions at operating and decommissioning facilities were similar, and the doses from gaseous effluents were within the ranges published in NRC (1996) for operating facilities. Both individual and collective doses were very low for liquid and gaseous effluents. Although information was available for a relatively small sample of facilities, there does not appear to be any reason to project substantial increases in emissions or public doses from reactors undergoing decommissioning compared to the levels experienced during normal operation of those facilities.

Table G-15. Summary of Effluent Releases Comparison of Operating Facilities and Decommissioning Facilities

Operating Reactors						
Reactor Type	**PWR**			**BWR**		
	Average	**Max**	**Min**	**Average**	**Max**	**Min**
Capacity (MWe)	829	912	760	972	1154	786
Gaseous Effluents - Total (Ci)	5.8E+01	1.5E+02	4.0E-01	9.3E+01	1.7E+02	1.2E+01
Fission and Activation Gases (Ci)	4.4E+01	1.4E+02	7.5E-02	8.3E+01	1.6E+02	1.5E+00
Iodines (Ci)	6.4E-07	1.3E-06	0	2.3E-03	5.1E-03	0
Particulates (Ci)	1.9E-05	3.8E-05	3.3E-07	8.9E-04	1.6E-03	3 0E-04
Gross Alpha (Ci)	--	--	--	--	--	--
Tritium (Ci)	1.4E+01	3.7E+01	3.2E-01	1.0E+01	1.2E+01	6.2E+00
Liquid Effluents - Total (Ci)	5.2E+02	6.7E+02	4.2E+02	1.2E+01	1.9E+01	6.9E+00
Fission and Activation Products (Ci)	1.6E-01	3.7E-01	8.5E-02	6.2E-02	9.4E-02	1.2E-02
Tritium (Ci)	5.2E+02	6.7E+02	4.2E+02	1.2E+01	1.9E+01	6.9E+00
Dissolved and Entrained Gases (Ci)	1.0E-01	3.8E-01	2.2E-04	4.3E-03	6.7E-03	1.8E-03
Gross Alpha (Ci)	1.2E-03	1.9E-03	4 4E-04	2.4E-06	3 8E-06	0
Decommissioning Reactors						
Reactor Type	**PWR**			**BWR**		
	Average	**Max**	**Min**	**Average**	**Max**	**Min**
Capacity, MWe	970	1080	860	65	67	63
Gaseous Effluents - Total (Ci)	2.1E+01	4.0E+01	2.6E+00	1.1E+02	2.1E+02	1.2E+00
Fission and Activation Gases (Ci)[(a)]	1.6E+01	1.6E+01	1.6E+01	2.1E+02	2.1E+02	2.1E+02
Iodines (Ci)	--	--	--	--	--	--
Particulates (Ci)	0	0	0	1.0E-04	2.0E-04	0
Gross Alpha (Ci)	--	--	--	0	0	0
Tritium (Ci)	1.3E+01	2.4E+01	2.6E+00	1.2E+00	1.2E+00	1.2E+00
Liquid Effluents - Total (Ci)	7.8E-01	1.4E+00	1.2E-01	3.3E-01	1.3E+00	1.0E-03
Fission and Activation Products (Ci)	3.5E-02	6.7E-02	2.6E-03	3.3E-01	1.3E+00	2.0E-04
Tritium (Ci)	7.4E-01	1.4E+00	1.2E-01	9.5E-04	1.1E-03	8.0E-04
Dissolved and Entrained Gases (Ci)	--	--	--	--	--	--
Gross Alpha (Ci)	0	3.0E-05	0	0	0	0

(a) The average, maximum, and minimum values for this radionuclide category are identical within each reactor type because only one facility of each type reported detectable emissions. Other facilities either did not report emissions for this category or indicated that emissions were below detection limits and, therefore, were not included in the calculation.

G.3 References

10 CFR 20. Code of Federal Regulations, Title 10, *Energy*, Part 20, "Standards for protection against radiation."

10 CFR 50. Code of Federal Regulations, Title 10, *Energy*, Part 50, "Domestic licensing of production and utilization facilities."

40 CFR 61. Code of Federal Regulations, Title 40, Protection of Environment, Part 61, "National emissions standards for hazardous air pollutants; regulations of radionuclides."

40 CFR 190. Code of Federal Regulations, Title 40, *Protection of Environment*, Part 190, "Environmental radiation protection standards for nuclear power operations."

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Appendix H

Summary of Environmental Impacts from Decommissioning Activities

Appendix H

Summary of Environmental Impacts from Decommissioning Activities

This appendix provides two tables that summarize findings from the analysis of the environmental impacts from decommissioning of permanently shutdown nuclear reactors. Table H-1 shows those issues and decommissioning activities that have no environmental impacts. Licensees may conduct these activities without further consideration of the potential environmental impacts. Table H-2 presents each environmental issue that was evaluated, provides the activities that were determined potentially to have environmental impacts, and then states whether the impacts related to the issue's associated activities were determined to be generic or site-specific for all variables. The significance level is identified and a short discussion of the finding is provided on the right-hand side of the table. Section 4.1 defines the significance levels and explains the distinction between generic or site-specific issues.

Table H-1. Issues and Activities with No Environmental Impacts

Issue	Activity
Onsite/Offsite Land Use	Remove fuel Organizational changes Stabilization Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlment phases of DECON, SAFSTOR, and ENTOMB1 System dismantlement Entombment Transportation License termination activities
Water Use	Remove fuel • Drain primary system • Process liquid Organizational changes • Adjust site training • Changes to licensing basis - site-specific Stabilization Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Large component removal • Steam generator and other large components intact or cut up Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Chemical decontamination (surface/specific components) • Decontaminate piping inside walls • Remove contaminated soil from specific areas • Do preventive and corrective maintenance on SSCs • Maintain the security system • Maintain effluent and environmental monitoring programs

Table H-1. (contd)

Issue	Activity
Water Use (contd)	System dismantlement Entombment • Install engineered barriers • Disconnect operational systems (e.g. electrical and fire protection) • Remove all radioactive material that is outside of containment • Place material inside containment LLW packaging and storage Transportation License termination activities
Water Quality	Organizational changes Stabilization • Isolate SSCs that are no longer required • Rewire site to eliminate unneeded electrical circuits Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Large Component Removal Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Chemical decontamination (surface/specific components) • Decontamination of piping inside walls • Remove contaminated soil from specific areas • Do preventive and corrective maintenance on SSCs • Maintain the security system • Maintain effluent and environmental monitoring programs System dismantlement Structure dismantlement • Removal of structures Entombment LLW packaging and storage Transportation License termination activities

Table H-1. (contd)

Issue	Activity
Air Quality	Remove fuel Organizational changes • Reduce staff • Adjust site training • Change licensing basis - site-specific Stabilization Rewire site to eliminate unneeded electrical circuits Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Large component removal Storage preparation activities for SAFSTOR • De-energize systems, put in monitors where they are needed • Perform a radiological assessment Storage (SAFSTOR) • Monitor systems and radiation levels etc. • Do preventive and corrective maintenance on SSCs • Maintain the security system Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Chemical decontamination (surface/specific components) • Decontamination of piping inside walls • High-pressure water sprays of surface • Remove contaminated soil from specific areas • Do preventive and corrective maintenance on SSCs • Maintain the security system System dismantlement Entombment • Disconnect operational systems (e.g., electrical and fire protection) • Remove all radioactive material that is outside of containment • Place material inside containment LLW packaging and storage License termination activities

Table H-1. (contd)

Issue	Activity
Aquatic Ecology	Remove fuel Organizational changes Stabilization Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Large Component Removal Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 System dismantlement Structure dismantlement • Rubblization Entombment LLW packaging and storage Transportation License termination activities
Terrestrial Ecology	Remove fuel Organizational changes Stabilization • Drain and flush system • Isolate SSCs that are no longer required Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Chemical decontamination (surface/specific components) • Decontamination of piping inside walls • High-pressure water sprays of surface • Do preventive and corrective maintenance on SSCs • Maintain the security system • Maintain effluent and environmental monitoring programs

Table H-1. (contd)

Issue	Activity
Terrestrial Ecology (contd)	System dismantlement Structure dismantlement • Rubblization Entombment LLW packaging and storage Transportation License termination activities
Threatened and Endangered Species	Remove fuel Organizational changes Stabilization • Drain and flush system • Isolate SSCs that are no longer required Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Chemical decontamination (surface/specific components) • Decontamination of piping inside walls • High-pressure water sprays of surface • Do preventive and corrective maintenance on SSCs • Maintain the security system • Maintain effluent and environmental monitoring programs System dismantlement Structure dismantlement • Rubbliztion Entombment LLW packaging and storage Transportation License termination activities
Radiological	Organizational changes • Changes to licensing basis - site-specific Create nuclear island • Reduce the security area to that around the fuel • Change security function • Install or modify chemistry controls

Table H-1. (contd)

Issue	Activity
Radiological (contd)	Storage (SAFSTOR) • Maintain the security system • Maintain effluent and environmental monitoring programs Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Maintain the security system • Maintain effluent and environmental monitoring programs Entombment • Entomb facility in concrete Transportation • Equipment into site • Backfill trucked into site • Nonradioactive waste
Radiological Accidents	Organizational changes • Reduce staff • Employ contractor or other additional staff Stabilization • Isolate SSCs that are no longer required • Rewire site to eliminate unneeded electrical circuits Post-shutdown surveys Create nuclear island Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Remove contaminated soil from specific areas • Do preventive and corrective maintenance on SSCs • Maintain the security system • Maintain effluent and environmental monitoring programs Structure dismantlement • Rubblization Entombment • Install engineered barriers • Disconnect operational systems (e.g. electrical and fire protection) • Remove all radioactive material that is outside of containment

Table H-1. (contd)

Issue	Activity
Radiological Accidents (contd)	• Place material inside containment • Entomb facility in concrete Transportation • Equipment into site • Backfill trucked into site • Nonradioactive waste License termination activities
Occupational Issues	Organizational changes • Reduce staff • Employ contractor or other additional staff • Changes to licensing basis Post-shutdown surveys Create nuclear island • Reduce the security area to that around the fuel • Change security function Storage preparation activities for SAFSTOR • Perform a radiological assessment Storage (SAFSTOR) • Monitor system and radiation levels • Maintain security system • Maintain efficient and environmental monitoring programs Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Maintain the security system • Maintain effluent and environmental monitoring programs Transportation • Equipment into site • Backfill trucked into site • Nonradioactive waste License termination activities • Partial site release

Table H-1. (contd)

Issue	Activity
Cost	Remove fuel • Transfer fuel to spent fuel pool Create nuclear island • Install or modify chemistry controls
Socioeconomic	Remove fuel Organizational changes • Adjust site training • Change licensing basis - site-specific Stabilization Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Large component removal Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 System dismantlement Structure dismantlement Entombment LLW packaging and storage Transportation License termination activities
Environmental Justice	Remove fuel Organizational changes • Adjust site training • Change licensing basis - site-specific Stabilization Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Large components removal Storage preparation activities for SAFSTOR Storage (SAFSTOR)

Table H-1. (contd)

Issue	Activity
Environmental Justice (contd)	Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 System dismantlement Structure dismantlement Entombment LLW packaging storage Transportation • Move equipment into site • Backfill trucked into site • Nonradioactive waste License termination activities
Cultural Impacts	Remove fuel Organizational changes Stabilization • Drain and flush system • Isolate SSCs that are no longer required Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Chemical decontamination (surface/specific components) • Decontamination of piping inside walls • High pressure water spray of surface • Do preventative and corrective maintenance on SSCs • Maintain security system • Maintain effluent and environmental monitoring programs System dismantlement Structure dismantlement Entombment LLW packaging and storage Transportation • Equipment into site • Backfill trucked into site • Nonradioactive waste License termination activities

Table H-1. (contd)

Issue	Activity
Aesthetic Issues	Remove fuel Organizational changes Stabilization Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Large component removal Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 System dismantlement Entombment • Disconnect operational systems (e.g. electrical and fire protection) • Remove all radioactive material that is outside of containment • Place material inside containment • Lower ceiling (optional) LLW packaging and storage Transportation License termination activities
Noise	Remove fuel Organizational changes Stabilization Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Large components removal Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 System dismantlement

Table H-1. (contd)

Issue	Activity
Noise (contd)	Entombment • Disconnect operational systems (e.g. electrical and fire protection) • Place material inside containment • Lower ceiling (optional) LLW packaging and storage Transportation License termination activities
Irretrievable Resources	Remove fuel Organizational changes Stabilization Post-shutdown surveys Create nuclear island Chemical decontamination of primary loop Large components removal Storage preparation activities for SAFSTOR Storage (SAFSTOR) Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 Entombment Transportation • Equipment into site License termination activities

Table H-2. Summary of Environmental Impacts

Onsite/Offsite Land Use (4.3.1)
Activities that Could Impact Onsite/Offsite Land Uses
Large Component Removal Structure dismantlement (Laydown yards) LLW packaging and storage
Generic
Yes - For onsite activities for all reactor types No - For offsite activities for all reactor types
Impact and Summary of Findings
• Onsite land use activities - SMALL • Offsite land use activities - site specific

Table H-2. (contd)

Water Use (4.3.2)
Activities that Could Impact Water Use
Remove Fuel • Transfer fuel to spent fuel pool Organizational changes (affects potable water use) • Reduce staff • Employ contractor staff or other additional staff Large Component Removal • Remove reactor vessel and internals Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • High-pressure water spray Structure dismantlement (dust control) Entombment • Lower containment ceiling (dust control) • Entomb facility in concrete
Generic
Yes - For all activities and reactor types
Impact and Summary of Findings
All activities related to water use that are identified in this Supplement - SMALL The amount of water used during decommissioning is much less than the amount of water used during operations except for possible short periods of time when potable water use may temporarily increase with staffing levels.

Table H-2. (contd)

Water Quality (4.3.3)
Activities that Could Impact Water Quality
Remove Fuel Stabilization • Drain and flush system Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • High-pressure water spray Structure dismantlement (pH concerns) • Rubblization
Generic
Yes - For surface water and groundwater for all reactor types
Impact and Summary of Findings
All activities related to water quality (surface and groundwater) that are identified in this Supplement except for onsite disposal of demolition debris - SMALL The releases during decommissioning are within the NPDES guidelines.

Table H-2. (contd)

Air Quality (4.3.4)
Activities that Could Impact Air Quality
Organizational changes (additional worker vehicle traffic) • Employ contractor staff or other additional staff Stabilization • Drain and flush system • Isolate system structures and components Preparation for Storage (SAFSTOR) • Reactor coolant system ventilation pathways • Containment ventilation pathways Storage (SAFSTOR) • Maintain effluent and environmental monitoring programs Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Maintain effluent and environmental monitoring programs Structural dismantlement (dust control) Entombment • Install engineered barriers (dust control) • Lower containment ceiling (dust control) • Entomb facility in concrete (vehicle traffic) Transportation
Generic
Yes - For all activities and reactor types
Impact and Summary of Findings
All activities related to air quality that are identified in this Supplement - SMALL Any fugitive dust from decommissioning activities are temporary and can be controlled by mitigative measures. Air quality impacts from workers' vehicles and for movement of materials to and from the site are expected to be negligible.

Table H-2. (contd)

Aquatic Ecology (4.3.5)
Activities that Could Impact Aquatic Ecology
Structure dismantlement • Remove structures that were necessary for plant operation (intake structure)
Generic
Yes - For activities within the operational area and reactor types No - Requires site-specific analysis if the activities are outside the boundaries of the operational area.
Impact and Summary of Findings
Activities within the boundaries of the operational areas - SMALL Activities outside the boundaries of the operational areas - site-specific

Table H-2. (contd)

Terrestrial Ecology (4.3.6)
Activities that Could Impact Terrestrial Ecology
Stabilization • Rewiring of site to eliminate unneeded electrical circuits (includes repowering from the outside) Large Component Removal Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Remove contaminated soil from specific areas Structure dismantlement • Remove structures that were necessary for plant operation
Generic
Yes - For activities within the operational area and for all reactor types No - Requires a site-specific analysis if the activities are outside the boundaries of the operational areas.
Impact and Summary of Findings
Activities within the boundaries of the operational areas - SMALL Activities outside the boundaries of the operational areas - site-specific

Table H-2. (contd)

Threatened and Endangered Species (4.3.7)
Activities that Could Impact Threatened and Endangered Species
Stabilization • Rewiring of site to eliminate unneeded electrical circuits (includes repowering from the outside) Large component removal Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Remove contaminated soil Structure dismantlement • Remove structures that were necessary for plant operation
Generic
No - Requires a site-specific analysis and continued monitoring of site activities concerning the presence of threatened and endangered species.
Impact and Summary of Findings
A site-specific analysis is required. The appropriate Federal agency (either U.S. Fish and Wildlife Service or the National Marine Fisheries Service) must be consulted about the presence of threatened or endangered species.

Table H-2. (contd)

Radiological (4.3.8)
Activities that Could Have Radiological Impacts
Remove Fuel Organizational changes • Reduce staff • Employ contractor or additional staff • Adjust site training Stabilization Post-shutdown surveys Create nuclear island • Install electrical power to SFP • Move old or install new security-related power Chemical decontamination of primary loop Large component removal SAFSTOR preparation SAFSTOR • Monitor systems and radiation levels • Preventive and corrective measures on SSCs

Table H-2. (contd)

Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Chemical decontamination • Decontaminate pipes in walls • High-pressure water sprays • Remove contaminated soil • Preventive and corrective maintenance on SSCs System dismantlement Structure dismantlement Entombment • Install engineered barriers • Disconnect operational systems • Remove radioactive material from outside of containment • Place material inside containment • Lower containment ceiling (optional) LLW packaging and storage Transportation • Large components • LLW License Termination Activities
Generic
Yes - For all activities and reactor types
Impact and Summary of Findings
Activities resulting in occupational doses to workers - SMALL Activities resulting in dose to the public - SMALL The long-term radiological aspects of Rubblization or onsite disposal of slightly contaminated material would require a site-specific analysis and would be addressed at the time the license termination plan is submitted.

Table H-2. (contd)

Radiological Accidents (4.3.9)
Activities that Could Impact Radiological Accidents
Remove Fuel Organizational changes • Adjust site training Stabilization • Drain and flush system Chemical decontamination of primary loop Large component removal Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Chemical decontamination • Decontamination inside pipe walls • High-pressure water sprays System dismantlement Structure dismantlement • Remove structures necessary for plant operations Entombment • Lower containment ceiling (optional) LLW packaging and storage Transportation • Large components • LLW
Generic
Yes - For all activities and reactor types
Impact and Summary of Findings
Activities resulting in accidents with offsite dose consequences - SMALL

Table H-2. (contd)

Occupational Issues (4.3.10)
Activities that Could Have Occupational Impacts
Remove fuel Organizational changes • Adjust site training Stabilization Create nuclear island • Install electrical power supply • Install or modify chemistry controls • Move old or install new security-related power Chemical decontamination of the primary loop Large component removal SAFSTOR preparation Storage (SAFSTOR) • Do preventive and corrective maintenance on SSCs Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Chemical decontamination • Decontaminate piping inside walls • High-pressure water sprays of surface • Remove contaminated soil System dismantlement • Do preventive and corrective maintenance on SSCs Structure dismantlement Entombment Low-level waste packaging and storage Transportation • Large components • LLW License termination activities • Complete final radiation survey
Generic
Yes - For all activities and reactor types
Impact and Summary of Findings
All activities related to occupational noise, temperature, ergonomic, and biological hazards if proper ES&H procedures are followed - SMALL

Table H-2. (contd)

Cost (4.3.11)
Activities that Could Have Socioeconomics Impacts
Removal Fuel • Drain primary system • Process liquid Organizational changes Stabilization Post-shutdown surveys Create nuclear island • Install electrical power to SFP • Reduce security area • Change security function • Move old or install new security-related power Chemical decontamination of primary loop Large component removal SAFSTOR preparation SAFSTOR Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 System dismantlement Structure dismantlement Entombment LLW packaging and storage Transportation License Termination Activities
Generic
No - Decommissioning costs are site specific
Impact and Summary of Findings
NA – Evaluation of decommissioning cost is not a NEPA requirement. This information is presented as a summary of actual and predicted decommissioning costs based on available data.

Table H-2. (contd)

Socioeconomics (4.3.12)
Activities that Could Have Socioeconomics Impacts
Organizational changes • Reduce staff • Employ contractor or other additional staff
Generic
Yes - For all activities and reactor types
Impact and Summary of Findings
All activities and reactor types - SMALL

Table H-2. (contd)

Environmental Justice (4.3.13)
Activities that Could Impact Environmental Justice
Organizational changes • Reduce staff • Employ contractor or other additional staff Transportation • Large components • LLW
Generic
No - Requires a site-specific analysis. The impacts depend on the location of and circumstances of minority and low-income populations in the vicinity of the plant.
Impact and Summary of Findings
A site-specific analysis is required. The licensee must provide, in their PSDAR submittal, appropriate information related to the issue of environmental justice.

Table H-2. (contd)

Cultural and Historic Impacts (4.3.14)
Activities that Could Have Cultural Impacts
Stabilization Large Component Removal Decontamination and dismantlement phases of DECON, SAFSTOR, and ENTOMB1 • Remove contaminated soil from specific areas
Generic
Yes - For activities within the operational area and reactor types
No - Requires a site-specific analysis if the activities are outside the boundaries of operational areas.
Impact and Summary of Findings
Activities are within the boundaries of the operational areas - SMALL
Activities are outside the boundaries of the operational areas - site specific

Table H-2. (contd)

Aesthetic Issues (4.3.15)
Activities that Could Have Aesthetic Impacts
Structure dismantlement Entombment • Install engineered barriers • Entomb facility in concrete
Generic
Yes - For all decommissioning activities
Impact and Summary of Findings
Visual intrusion would be temporary and would serve to reduce the aesthetic impact of the site for most decommissioning activities - SMALL

Table H-2. (contd)

Noise (4.3.16)
Activities that Could Have Noise Impacts
Structure dismantlement Entombment • Install engineered barriers • Remove radioactive structures outside containment • Entomb facility in concrete
Generic
Yes - For all activities and reactor types
Impact and Summary of Findings
Noise levels are easily controlled during most decommissioning activities - SMALL

Table H-2. (contd)

Transportation (4.3.17)
Issues that Could be Impacted by Transportation Activities
Air Quality Radiological Radiological accidents Cost Environmental justice Irretrievable resources
Generic
Yes - For all activities and reactor types
Impact and Summary of Findings
All activities, both radiological and nonradiological, related to transportation that are identified in this Supplement - SMALL

Table H-2. (contd)

Irretrievable Resources (4.3.18)
Activities that Could Impact Irretrievable Resources
System dismantlement Structure dismantlement LLW packaging and storage Transportation • Large components • LLW • Backfill trucked into site • Nonradioactive waste
Generic
Yes - For all decommissioning activities
Impact and Summary of Findings
All activities and options related to irretrievable resources - SMALL

Appendix I

Radiological Accidents

Appendix I

Radiological Accidents

The information below summarizes the review of existing information on accidents at decommissioning nuclear power facilities using the DECON or SAFSTOR option. The ENTOMB option was not included in this review because of the lack of available information; however, accidents would likely be similar to the DECON option during preparation of the facility for entombment. The purpose of this review was to determine the potential accidents that could occur at nuclear power facilities that have permanently ceased operations. When available, the potential offsite doses from these accidents were analyzed to determine which accidents could have the greatest offsite impact. This appendix provides an assessment of the activities conducted during decommissioning and determines whether accidents of greater consequence may occur during those activities.

As indicated in the Introduction to this Supplement, although the staff relies on the Commission's Waste Confidence Proceeding Finding, which states, in part, that there is, "reasonable assurance that, if necessary, spent fuel generated in any reactor can be stored safely and without significant impact for at least 30 yrs beyond the licensed life for operation...of that reactor at its spent fuel storage basin..." (54 Federal Register 39767),[a] the staff has elected to include in this Supplement a discussion of potential accidents related to the storage and maintenance of fuel in a spent fuel pool.

Three sources of information were reviewed to obtain a list of potential accidents and their consequences: (1) U.S. Nuclear Regulatory Commission (NRC) research efforts, including NUREGs, NUREG/CRs, and the 1988 GEIS (NRC 1988), (2) industry-related publications and documents, and (3) licensing-basis documents for the individual plants, such as post-shutdown decommissioning activity reports (PSDARs), decommissioning plans, final safety analysis reports (FSARs) or FSAR-equivalent documents, or environmental reports (ERs) developed by the licensee. A list of documents used for this analysis is provided in Section I.5. Included as well were environmental assessments (EAs), environmental impact statements (EISs), safety evaluations, or emergency exemptions that were written by NRC. Twenty of the 22 plants listed in Chapter 3 were included in the analysis, which was completed in late 1999. Zion, Units 1 and 2, the most recent plants to permanently cease operations, were not included.

(a) The Commission reaffirmed this finding of insignificant environmental impacts in 1999. This finding is codified in the Commission's regulations in 10 CFR 51.23(a).

I.1 Potential Accidents Considered During Decommissioning

Table I-1 contains a list of the accidents that were considered for both pressurized water reactors (PWRs) and boiling water reactors (BWRs) during decommissioning in early studies on safety and the cost of decommissioning PWRs and BWRs (Smith et al. 1978 and Oak et al. 1980, respectively). Both documents also considered several other types of accidents that were determined to be either of low probability or to result in very small releases, as shown in Table I-2. These accidents are listed along with a brief description or discussion of the accidents, as given in Smith et al. (1978) and Oak et al. (1980). The discussion in this section does not evaluate whether the accidents described in Smith et al. (1978) or Oak et al. (1980) should still be considered appropriate to the decommissioning process. As a result of improvements in the technology used for decommissioning, several of the accidents listed in Table I-2 may now be considered to be of a much lower probability or, at the least, to result in much-reduced consequences. For example, the use of a single failure-proof crane significantly reduces the potential for certain postulated spent fuel cask drops or heavy load accidents. Table I-3 provides a comprehensive list of accidents of potential accidents at facilities undergoing decommissioning, including HTGRs and FBRs.

The 1988 GEIS (NRC 1988) also considered accidents that could potentially occur during decommissioning. The list of postulated accidents was developed from the lists given in Smith et al. (1978) and Oak et al. (1980). However, not all accidents contained in these two documents were included in the 1988 GEIS, as shown by the footnote in Table I-1.

The staff conducted a study of spent fuel pool accident risk at decommissioning nuclear power facilities to support development of a risk-informed technical basis for reviewing exemption requests and a regulatory framework for integrated rulemaking (NRC 2001). Earlier analyses in NUREG/CR-4982, *Severe Accidents in Spent Fuel Pools in Support of Generic Issue 82*, (Sailor et al. 1987) and NUREG/CR-6451, *A Safety and Regulatory Assessment of Generic BWR and PWR Permanently Shutdown Nuclear Power Plants* (Travis et al. 1997) included a limited analysis of the offsite consequences of a severe spent fuel pool accident. As part of its effort to develop generic, risk-informed requirements for decommissioning, the staff performed a further, analysis of the offsite radiological consequences of beyond-design-basis spent fuel pool accidents. The external event initiators included:

- seismic events (earthquakes)
- aircraft crashes
- tornadoes and high winds

Table I-1. Summary of Accidents for PWR and BWR Plants Undergoing Decommissioning Operations[a]

Pressurized Water Reactors	Boiling Water Reactors
Explosion of liquid propane gas leaked from a front-end loader – Explosion ruptures filters and prefilters in the purge exhaust filter banks in containment.	**Explosion of liquid propane gas leaked from a front-end loader** – Used to load concrete rubble in the reactor building Assumed to occur in building ventilation ductwork and to cause failure of filters and blowers as well as to release radioactive contamination that is deposited on the high-efficiency particulate air (HEPA) filters and in the ductwork
Explosion of oxyacetylene during segmentation of the reactor pressure vessel – Postulated during segmenting of the reactor pressure vessel in the reactor cavity. Explosion is sufficient to cause failure of the HEPA filter in the contamination control envelope.	**Oxyacetylene explosion** – During use of oxyacetylene cutting torch to remove the activated portion of the reactor vessel in air before segmenting the removed sections under water.
Explosion and/or fire in the ion exchange resin – Explosive release of an ion exchange column in a nuclear waste facility.	--
Detonation of Unused Explosives in the Reactor Cavity[b] – A charge used to scarf the bioshield is detonated when the water spray is turned off, and the blasting mat and contamination control envelope are not in place.	**Detonation of unused explosives** – Assumes that a charge positioned to remove the sacrificial shield explodes when the water sprays are off and the contamination control envelope has been removed.
Fire in contaminated sweeping compound[b] – Sweeping compound is composed of sawdust treated with oil or other additives to enhance pickup of contamination. Postulated to catch fire spontaneously. Contains contamination from the floor surfaces	**Contaminated sweeping compound fire** – Sweeping compound is composed of sawdust treated with oil or other additives to enhance collection of loose surface contamination. A fire is postulated to occur in used sweeping compound contaminated with radioactive material.
Gross leak during *in situ* decontamination – Leak of 10 times the magnitude of the routine *in situ* decontamination leak for 30 minutes.	**Gross leak during loop chemical decontamination** – A massive failure of reactor piping during loop chemical decontamination is assumed to be low. This accident involves a gross leak about 10 times larger than the spray lead. A total of 1% of the liquid in the system is assumed to be made airborne.
Segmentation of reactor coolant system (RCS) piping with unremoved contamination – Released to the reactor containment building since no contamination-control envelope is assumed to be used.	–

Table I-1. (contd)

Pressurized Water Reactors	Boiling Water Reactors
Loss of contamination control envelope during oxyacetylene cutting of the reactor vessel shell – Molten metal particles penetrate the plastic sheet walls. Release lasts 5 minutes.	**Contamination control envelope rupture** – During oxyacetylene cutting. Molten metal particles penetrate the plastic sheet walls and increase leakage into the reactor building. Assumed to occur during the removal of the reactor vessel. Assumed large leak occurs for 1 hour of cutting before it is detected.
Pressure surge damage to filters during blasting of activated concrete bioshield[b]	**Filter damage from blasting surges** – During removal of activated concrete in the sacrificial shield.
Loss of blasting mat during removal of activated concrete[b] – Protective blasting mat is lost during blasting, and confinement barriers could be breached.	--
Temporary loss of local airborne contamination control during blasting[a] – A contamination control envelope is required in the reactor containment building during the explosive removal of the contaminated concrete in the biological shield. Loss of fine fog spray and contamination control increases the dust made airborne.	--
Loss of integrity of portable filtered ventilation enclosure during segmentation of the steam generators[b] – Substantial breach occurs and is readily apparent. Segmenting is promptly terminated. Air flow continues for 10 minutes.	--
Vacuum bag rupture – Metal shards rupture the filter bag and puncture the vacuum cleaner, releasing all the collected material into the air.	**Vacuum filter-bag rupture** – From metal shard, releasing all collected material to the reactor building.
Fire involving contaminated clothing or combustible waste[b] – Assumed 1 m^3 (35 ft^3) of combustible waste (absorbent materials such as rags or paper wipes).	**Combustible waste fire** – Assumed 1 m^3 (35 ft^3) of combustible waste (absorbent materials such as rags or paper wipes).
Accidental cutting of contaminated piping – Caused by human error. Assumed pipe is 25 cm (10 in.) or smaller.	--
Accidental spraying of concentrated contamination with the high-pressure spray – Postulated to be in the thermal insulation that has hidden a slow leak for a number of years. Results in an airborne release.	-

Table I-1. (contd)

Pressurized Water Reactors	Boiling Water Reactors
Accidental break of contaminated piping during inspection[b] – Occurs during SAFSTOR in reactor building. Pipe is weakened by corrosion and becomes damaged by incidental jostling or hitting of pipe. Assumed not to have been decontaminated *in situ*. Ventilation system is not operating.	--
Minor accidents with closed van	**Minor transportation accident** – Truck collision or overturn with waste containers that may rupture, or a collision and overturn with a minor fire (½ hour or less) involving one Type A waste container.
Moderate accidents with closed van	--
Severe accidents with closed van	**Severe transportation accidents** – Truck collision or overturn and a major fire (1 hour or longer) involving 40 Type A waste containers.

(a) All accidents listed are from Smith et al. (1978) and Oak et al. (1980).
(b) These accidents were not included in the 1988 GEIS (NRC 1988).

- compression or buckling of stored assemblies from the impact of a dropped heavy load (such as a fuel cask)

- loss of neutron absorber plates that separate the stored assemblies.

The results of the staff's analysis is presented in Section I.2.

The accidents and malfunctions considered in licensing documents were divided into subgroupings within five main categories:

- fuel-related accidents, which center around the storage of fuel in the spent fuel pool

- other radiological, non-fuel-related accidents, which include onsite accidents related to decontamination or dismantlement activities (e.g., material-handling accidents or accidental cutting of contaminated piping), or storage activities (e.g., fires or ruptures of liquid waste tanks)

- external events, which include aircraft crashes, floods, tornadoes and extreme winds, earthquakes, volcanic activity, forest fires, lightning storms, freezing, and intruder events

Table I-2. Accidents Considered but Not Evaluated in Smith et al. (1978) and Oak et al. (1980)

Pressurized Water Reactors	Boiling Water Reactors
Accidents involving fuel – Extensively studied and considered in other references. Not unique to or amplified by decommissioning.	--
Temporary loss of local airborne containment control during jackhammer scarfing of concrete surfaces – Manual operation, so the loss of local airborne containment is readily apparent to operator. Operation is suspended before significant release occurs.	--
Dropping of contaminated concrete rubble – Causing fine particles to become suspended in air. Quantity of such material is assumed to be small since most of the readily suspendible particles are removed during routine operations.	--
Dropping a concrete slab during placement in onsite retrievable waste storage – Precast concrete slab used for top shield and sealing surface is dropped 6 m (20 ft) while it is being placed. Surface particles become airborne, but do not increase routine release significantly and are not considered further in this study.	--
--	**Ion-exchange resin accidents** – Assumes no danger of combustion. Handling accidents appear likely, but would lead to little airborne release because of liquid nature of wastes involved.
Temporary loss of services, such as water, power, or airflow – Constitutes a lesser hazard for airborne releases than other postulated accidents.	**Loss of services, such as water supply, electrical power, or air flow** – Constitutes a lesser magnitude release than other postulated accidents, so no further analysis was made.
Natural phenomena – Reference PWR is designed to withstand effects of natural phenomena. It is assumed that this structural integrity is preserved during decommissioning as long as required for safety. These are low-probability events, e.g., floods, earthquakes, tornadoes, and high winds.	**Natural phenomena** – Reference BWR is designed to withstand the most severe natural phenomena recorded for the site with appropriate margins for uncertainties. Events are of low probability, and impact is less than the impacts calculated for operating BWRs. Includes floods, earthquakes, tornadoes, and high winds.
Aircraft crashes – Probability is low, risk is not escalated by dismantlement operations.	**Aircraft crashes** – Probability is low and risk of damage is low and not escalated by dismantlement operations.
--	**Man-caused events** – Covers wide spectrum of magnitude, ranging from releases induced by casual trespassers to releases induced by armed terrorists. Detailed analysis beyond scope of study.

- offsite events, which consist solely of transportation accidents that occur offsite
- hazardous, nonradiological, chemical-related accidents, with the potential for injury to the offsite public either directly from the accident, or as a result of further actions initiated by the accident.

Table I-3 contains the list of accidents as described in the licensing documentation for each of the 20 plants reviewed. The accidents are organized under the five category headings shown above and under subgroup headings that describe a specific type of accident, e.g.,"cask or heavy load handling accidents" or "spent resin accidents." Each of the plants described the accidents they evaluated in a specific way, which may or may not be identical to the subgroup headings. For example, Big Rock Point considered a "loss of spent fuel pool cooling," while the Trojan Nuclear Plant described a similar accident as a "loss of spent fuel decay heat removal without concurrent spent fuel pool inventory loss." The exact descriptions given by the plants were used when available. In some cases, however, a short description was not available, and it was necessary to paraphrase or summarize from a longer discussion of the accident.

Categorizing accidents is not a straightforward process. Frequently, an initiating event causes more than one type of accident. For example, the loss of electric power could cause the loss of spent fuel cooling, resulting in the potential for fuel failure and subsequent offsite release. The same loss of electric power could result in a crane or hoist failure, resulting in a heavy object being dropped either into the spent fuel pool with subsequent failure of fuel cladding, or in a highly contaminated object other than fuel being dropped onto an unyielding surface, causing the release of contamination. The same loss of electric power could affect the ventilation system and result in the loss of high-efficiency particulate air (HEPA) filtration and subsequent release of contamination. Alternatively, a single accident could be caused by multiple types of initiating events. For example, the loss of spent fuel pool coolant could be caused by the loss of offsite power, a break in a pipe (resulting from cutting the wrong pipe), or an external event (such as damage to the pipes from freezing or rupture of the pool during an earthquake) causing the release of the water. Because an effort was made to categorize the accidents as they were described by the licensing documents for each plant, a "loss of offsite power accident" may be the same thing as a "loss of spent fuel cooling accident." In some cases, a single plant would analyze both the loss of offsite power and the loss of spent fuel pool cooling as separate accidents, whereas they both concluded with the same result.

Table I-3. Comprehensive Accident List

Fuel-Related Accidents	Nuclear Plant
Cask or Heavy Load Handling Accident	
Cask drop into spent fuel pool	Haddam Neck
Spent fuel shipping cask drop in the spent fuel pool	Maine Yankee
Spent fuel cask drop	San Onofre, Unit 1
Shipping cask or heavy load drop in fuel element storage well	La Crosse
Heavy load drop (equivalent to spent fuel cask drop) into pool	Big Rock Point
Drop of heavy object (cask) into spent fuel pool	Indian Point, Unit 1
Heavy load drop (equivalent to spent fuel cask drop) into spent fuel pool	Humboldt Bay, Unit 3
Heavy load drop	Fort St. Vrain
Spent Fuel-Handling Accident	
Fuel assembly drop	Haddam Neck
Fuel-handling accident	Trojan
Fuel-handling accident	San Onofre, Unit 1
Fuel-handling accident	Rancho Seco
Spent fuel handling accident	Humboldt Bay, Unit 3
Spent fuel handling event	Yankee Rowe
Fuel-assembly handling accident in the spent fuel pool	Maine Yankee
Spent fuel handling accident in fuel element storage well	La Crosse
Loss of Spent Fuel Pool Cooling	
Loss of spent fuel pool cooling water (caused by loss of offsite power)	Big Rock Point
Loss of fuel pool cooling	Indian Point, Unit 1
Loss of spent fuel pool cooling water	Yankee Rowe
Loss of fuel element storage well cooling	La Crosse
Loss of prestressed concrete reactor vessel shielding water (after fuel has been removed)	Fort St. Vrain
Loss of spent fuel pool decay heat-removal capability	Maine Yankee
Loss of spent fuel decay heat-removal without concurrent spent fuel pool inventory loss	Trojan
Failure of auxiliary electrical systems related to fuel pool cooling	Dresden, Unit 1
Loss of offsite power; limited loss of spent fuel pool cooling	San Onofre, Unit 1
Nonmechanistic loss of cooling and airborne release	Humboldt Bay, Unit 3
Loss of Water from the Spent Fuel Pool	
Loss of spent fuel pool water level	Big Rock Point
Loss of spent fuel pool water (nonmechanistic; earthquake beyond design basis)	Haddam Neck
Loss of spent fuel pool water	Indian Point, Unit 1
Loss of spent fuel pool inventory (loss of heat sink or by inadvertent siphoning)	Maine Yankee
Loss of spent fuel pool water from pool rupture of unknown origin	Humboldt Bay, Unit 3
Loss of cooling water	Yankee Rowe
Fuel pool drain-down	Dresden, Unit 1

Table I-3. (contd)

Fuel-Related Accidents (contd)	Nuclear Plant
Fuel element storage well system pipe break	La Crosse
Loss of spent fuel pool decay heat-removal capability with concurrent spent fuel pool inventory loss	Trojan
Loss of Offsite Power	
Loss of offsite power (resulting in loss of spent fuel cooling)	Big Rock Point
Loss of offsite power (resulting in loss of water from the pool)	La Crosse
Loss of offsite power (resulting in loss of spent fuel pool cooling)	Rancho Seco
Loss of power	Fort St. Vrain
Temporary loss of offsite power (crane or hoist failure)	Trojan
100% Fuel Failure	
100% fuel failure	Indian Point, Unit 1
100% fuel failure	Shoreham
Simultaneous failure of fuel assemblies	Dresden, Unit 1
Criticality	
Inadvertent criticality (misplaced assembly in pool)	Maine Yankee
Criticality, stored spent fuel rearranged from seismic or other events	Humboldt Bay, Unit 3
Accidents Involving Radioactive Materials (Non-Fuel-Related)	
Decontamination-Related Accidents	
Spray release during in situ decontamination of systems	Saxton
Gross leak or accident during in situ decontamination (spray and liquid)	Trojan
Decontamination of liquid spill	Three Mile Island, Unit 2
Decontamination events	Yankee Rowe
Accidental spraying of concentrated contamination with high-pressure spray	Three Mile Island, Unit 2
Concentrated contamination spray	Three Mile Island, Unit 2
Radioactive Material (Non-fuel) Handling Accidents	
Waste container drop	Pathfinder
Waste container drop and rupture (containing activated concrete rubble)	Shoreham
Dropping of filters or packages of particulate material	Trojan
Dropping of contaminated components	Trojan
Dropping of concrete rubble	Fort St. Vrain
Dropping of concrete rubble	Trojan
Packaging events	Yankee Rowe
Materials-handling event	Yankee Rowe
Steam generator load drop inside containment	Trojan
Dropping the reactor pressure vessel	Pathfinder
Dropping steam generator primary module	Fort St. Vrain
Steam generator load drop outside of containment	Trojan

Table I-3. (contd)

Accidents Involving Radioactive Materials (Non-Fuel-Related) (contd)	Nuclear Plant
Dismantlement-Related Accidents	
Contamination release during accidental cutting of contaminated piping	Three Mile Island, Unit 2
Contamination release during accidental break of contaminated piping	Three Mile Island, Unit 2
Loss of engineering controls during dismantlement of reactor cavity	Big Rock Point
Contamination release during dismantlement of main coolant system loop	Yankee
Dismantlement of RCS and safety injection piping without or with loss of local engineering controls	Saxton
Absence of blasting mat during removal of activated concrete	Trojan
Loss of HEPA Filters	
Rupture of contamination-control envelope; release of contamination on HEPA filter	Shoreham
HEPA filter failure	Three Mile Island, Unit 2
Loss of integrity of portable filtered ventilation enclosure	Trojan
Pressure-surge damage to filters during blasting of activated concrete bioshield	Trojan
Temporary loss of local airborne contamination control during blasting	Trojan
Temporary loss of local airborne contamination control during scarfing of contaminated concrete surfaces with jackhammer	Trojan
Loss of contamination-control envelope during oxyacetylene cutting of the reactor-vessel shell	Trojan
Radioactive Gas Waste System Leaks	
Leaks and failures in radioactive waste gas system in radwaste decay tanks	Maine Yankee
Leak or failure in radioactive waste gas system	Trojan
Radioactive Liquid Waste Releases	
Liquid waste tanks rupture	Fermi, Unit 1
Storage tank rupture	Three Mile Island, Unit 2
Liquid waste storage vessel failure	Saxton
Postulated radioactive releases due to liquid tank failures	Trojan
Liquid radioactive tank release	Humboldt Bay, Unit 3
Liquid radioactive waste release to lake through cracks in building, earthquake-induced	Fermi, Unit 1
Rupture of spent fuel pool, contents released to bay	Humboldt Bay, Unit 3
Liquid waste discharge pumped to river without sampling	La Crosse
Leaks and failures in radioactive liquid waste system	Maine Yankee
Condensate storage tank contents pumped into ground during in-service leak test (actual event report)	Dresden, Unit 1
Containment Breach (Open Penetration to Containment)	
Containment vessel breach, subsequent loss of contents to air/water	Saxton
Open penetration – unfiltered pathway from containment	Three Mile Island, Unit 2

Table I-3. (contd)

Accidents Involving Radioactive Materials (Non-Fuel-Related) (contd)	Nuclear Plant
Release of helium coolant	Peach Bottom 1
Spent Resin Accidents	
Spent resin handling accident (exothermic reaction during dewatering)	Haddam Neck
Dropped resin vessel during removal from containment building	Saxton
Low-level waste storage accident (resin liner drop)	Maine Yankee
Release of resins from makeup and purification demineralizer	Three Mile Island, Unit 2
Storage of spent resins	Big Rock Point
Explosion and/or fire in ion exchange resins	Trojan
Vacuum Filter Bag Ruptures	
Vacuum filter bag rupture during decontamination of spent fuel pool floor	Saxton
Vacuum filter bag rupture during cleaning of the Reactor Building floor	Shoreham
Vacuum canister failure	Three Mile Island, Unit 2
Loss of Electric Power	
Loss of offsite power	Yankee Rowe
Loss of offsite power	Trojan
Loss of electric power with unknown scenario	Pathfinder
Loss of offsite power affecting HEPA filters, etc.	Saxton
Loss of Compressed Air	
Temporary loss of compressed air	Trojan
Loss of compressed air	Yankee Rowe
Fire	
Fire	Dresden, Unit 1
Fire	San Onofre, Unit 1
Fire	Fort St. Vrain
Fire	Indian Point, Unit 1
Fire events (primarily those that could impact SFP cooling)	Big Rock Point
Fire inside of containment	Three Mile Island, Unit 2
Fire inside reactor vessel	Peach Bottom 1
Fire inside stairwell	Three Mile Island, Unit 2
Fire in D-rings	Three Mile Island, Unit 2
Fire in reactor building or fuel handling building	Pathfinder
Fire in boiler building	Pathfinder
Fire in storage facilities	Yankee Rowe
Fire in intermodel container of waste	Yankee Rowe
Fire in combustible waste stored in yard	Saxton
Fire in low-level radioactive waste storage building	Trojan
Combustible waste fire in 208-L (55-gal) drum container	Shoreham
Contaminated clothing or combustible waste fire	Trojan

Table I-3. (contd)

Accidents Involving Radioactive Materials (Non-Fuel-Related) (contd)	Nuclear Plant
Contaminated sweeping compound fire (sawdust with oil and other additives, used to enhance collection of loose surface contaminants)	Shoreham
Fire or other catastrophic event, initiator for residual sodium release	Fermi, Unit 1
Explosion	
Explosion of liquid propane gas leaked from front-end loader in containment	Trojan
Liquid propane gas explosion on front-end loader	Shoreham
Liquid propane gas explosion caused by an accidental leak on front-end loader used in containment building	Saxton
Oxyacetylene explosion in the containment building while cutting reactor coolant system piping and release of HEPA filter contents within portable enclosure	Saxton
Oxyacetylene explosion and release of HEPA filter contents	Shoreham
Explosion of oxyacetylene during segmenting of reactor vessel shell	Trojan
Explosion event inside vapor container	Yankee Rowe
Explosion inside area warehouse	Yankee Rowe
Explosion of large fuel-oil storage tanks	Humboldt Bay, Unit 3
Detonation of unused explosives in reactor cavity	Trojan
Sodium interaction with water caused by water inflow through a crack in a tank	Fermi, Unit 1
Onsite Transportation Accidents	
Onsite transportation accident	Yankee Rowe
Accidents Initiated in External Events	
Aircraft Crashes	
Aircraft hazards	Big Rock Point
Aircraft crashes	Trojan
Aircraft impact	Yankee Rowe
Floods	
Flood	San Onofre, Unit 1
Flood	Yankee Rowe
Flood	Pathfinder
Flooding	Saxton
External flooding	Big Rock Point
External flooding	Trojan
Site flooding	Dresden, Unit 1
Site flooding	Indian Point, Unit 1
Site flooding	Peach Bottom, Unit 1
Flood, seiches, and tsunamis	Shoreham
Low Water	
Probable minimum water level, from negative lake surge or sieche	Big Rock Point

Table I-3. (contd)

Accidents Initiated in External Events (contd)	Nuclear Plant
Wind	
Tornadoes and extreme winds	Pathfinder
Tornadoes and extreme winds	Trojan
Tornadoes and extreme wind	Yankee Rowe
Tornadoes and extreme wind	Saxton
Tornadoes and wind	Big Rock Point
Wind and tornadoes	La Crosse
Wind and tornado missiles	San Onofre, Unit 1
Tornados and hurricanes	Shoreham
Natural disaster, tornado	Fort St. Vrain
Earthquakes	
Earthquake	Big Rock Point
Earthquake	Indian Point, Unit 1
Earthquake	Pathfinder
Earthquake	Trojan
Earthquake	Saxton
Earthquake	San Onofre, Unit 1
Earthquake	Shoreham
Earthquakes	Yankee Rowe
Seismic events	Dresden, Unit 1
Seismic event	La Crosse
Volcanoes	
Volcanic activity	Trojan
Lightning	
Lightning	Trojan
Lightning	Saxton
Lightning	Yankee Rowe
Forest Fire	
Forest fires	Yankee Rowe
Forest or brush fire	Saxton
Freezing Temperatures	
Freezing temperatures, loss of plant heating	Big Rock Point
Freezing temperatures (actual accident)	Dresden, Unit 1
Physical Security	
Intruder event	Saxton
Physical security breach	Shoreham
Physical security breach	Pathfinder

Table I-3. (contd)

Offsite Transportation-Related Accidents	
Offsite transportation accident	Shoreham
Offsite transportation accident	Yankee Rowe
Transportation accident	Three Mile Island, Unit 2
Truck carrying radwaste – fire	Pathfinder
Truck and two intermodel containers, transportation accident with fire	Saxton
Reactor pressure vessel railroad accident and fire	Pathfinder
Reactor pressure vessel in the river during transportation by rail	Pathfinder
Offsite radiological event (shipment of radioactive materials)	Saxton
Hazardous Nonradiological Chemical Events	
Toxic chemical event (initiation for material handling event)	Saxton
Toxic chemical event	Trojan
Chemical combustion (from sodium-water interaction) and dispersal	Fermi, Unit 1
Toxic chemical event, initiator for fuel-handling event	Trojan

All accidents identified by licensees were included in Table I-3, even if they were just considered without a detailed discussion or analysis of the consequences. A number of accidents were initially considered, but were determined without further analysis to fall under one of the following categories:

- an accident that is not possible or probable – For example, a licensee might consider an aircraft impact as an accident, but state in their documentation that the probability of occurrence is low and, therefore, the accident is not analyzed further.

- an accident may occur, but not result in any type of consequence – For example, during consideration of a flood, the licensee might state that "flooding events do not result in significant radiological release; therefore, public health and safety are not adversely affected," or in the case of a material-handling event, make a statement such as, "compliance with management programs and quality assurance plan ensure that the probability of occurrence and the consequences do not significantly affect the public health and safety."

- an accident may occur, but mitigative actions can be taken before any radioactive material is released offsite – For example, during consideration of a seismic event, a statement is made that the facility was designed to accommodate the initiating event, and no damage resulting in a release would occur.

- an accident may occur, but with minimal offsite dose consequences – For example, loss of cooling for a spent fuel pool where the fuel has cooled to a level that would not result in the release of activity for a number of days and where mitigative actions could be taken to ensure that there would be no release of radioactive materials.

Although these accidents were not analyzed in depth, they were considered and, therefore, are included in Table I-3.
Most licensees did not describe the entire scenario that would cause the accident. For example, most documents that discussed the analysis of the release of liquid radioactive waste did not provide an indication of the event that caused the rupture of a liquid waste tank or storage tank. Therefore, it was a simple decision to place this accident in the group of "Liquid Radwaste Releases." However, some licensees did provide a complete scenario, such as a description that the tanks located in the basement were assumed to have been cracked during an earthquake, allowing fluid to leak into the earth and then into an aquifer, finally settling in a nearby lake. This accident could have been grouped by the initiating event (an earthquake) or the consequence (a release of liquid radioactive waste). In such cases, the initiators (or the consequences) are also shown in Table I-3.

In other cases, the accident could easily be placed under more than one heading. For example, one licensee (Trojan Nuclear Plant) analyzed an explosion and/or fire in the ion exchange resins. This accident could have been included under "Explosions," "Fires," or "Spent Resin Accidents." In this case, the last choice was selected. Another example would be the "oxyacetylene explosion and release of HEPA filter contents," which was analyzed by the licensees for the Saxton, Shoreham, and Trojan Nuclear Plants. This accident could have been included under either "Explosions" or "Loss of HEPA filters." In this case, the first choice was selected.

In some cases, the descriptions provide much more information regarding the accident than they do in other cases. For instance, under the heading "Fire," five of the licensees did not give any more detailed description other than they were analyzing a "fire" or "fire events." Other licensees described the location of the fire (inside stairwells, inside boiler buildings, etc.), and the remainder discussed the items that were combusted (contaminated clothing or waste, or contaminated sweeping compound).

Some of the descriptions of the accidents did not give any details regarding the scenario that resulted in offsite dose consequences. These accidents were described as nonmechanistic, i.e., they had no associated scenarios or initiators. For example, three licensees evaluated the simultaneous failure of 100% of the fuel assemblies in the spent fuel pool but gave no reason for the simultaneous failure.

The fuel-related accidents centered around the storage of the spent fuel in the spent fuel pool. The most common fuel-related accidents analyzed include the loss of spent fuel pool cooling (10 facilities), the loss of water in the spent fuel pool (9 facilities), cask or heavy handling (8 facilities), and the spent fuel handling (8 facilities). The accidents listed under "Loss of Offsite Power Accidents" also result in the loss of cooling, the loss of water from the pool, or a handling accident.

The non-fuel-related accidents center around decontamination, dismantlement, or storage-type activities. Decontamination-related activities include *in situ* decontamination and rupture of vacuum-filter bags. Accidents from these activities could include fires that occur in contaminated clothing or sweeping compounds. Dismantlement-related activities include accidental cutting or breaking of contaminated piping or breaching of containment, loss of HEPA filters during cutting or blasting operations, and material-handling accidents, such as dropping of contaminated components, concrete rubble, or spent resins. Dismantlement activities also include the potential for explosions either from front-end loaders or while using oxyacetylene during dismantlement activities. Storage-type activities include storage of non-fuel wastes that could result in liquid waste tank ruptures and explosive gas buildup in ion exchange resins. There is also the potential for fires in buildings or in waste stored inside the facility.

The most common non-fuel-related accidents that involved radioactive material were the fires (20 total accidents from 12 different plants). A fire may be one of the more important accidents to consider for a plant in decommissioning because of the large loading of combustible material resulting from the amount of low-level radioactive waste in the form of wipes, clothing, etc. Fire events included generic listings of "fire," specific listings of locations where the fire might occur (in the boiler building or low-level waste storage buildings) or the material the fire involves (contaminated clothing or contaminated sweeping compounds).

The second most common non-fuel-related accident related to the handling of radioactive (non-fuel) material such as waste containers, filters, concrete rubble, contaminated components, or larger items such as reactor pressure vessels or steam generators (13 accidents identified from 5 separate plants). The third most common radiation-related (non-fuel) accident was from explosions, which comprise 11 accidents from 5 separate plants. These accidents included explosion of liquid propane gas from front-end loaders being used for dismantlement activities and oxyacetylene explosions during dismantlement, which released HEPA filter contents, or during the reactor vessel shell. The fourth most common non-fuel-related accident is the release of liquid radioactive waste from storage tanks. The majority of these accidents resulted from the rupture or failure of a tank storing liquid radioactive waste. However, one of the postulated accidents occurs during the inadvertent pumping or transfer of the liquid radioactive waste to the river without sampling. Another of the postulated accidents in this group was the rupture of the spent fuel pool, with the contents released to a nearby body of water. This accident looked at the offsite dose consequences of the contaminated water being released to

the environment and did not consider the resultant effect on the spent fuel remaining in the now-drained pool (considered a separate accident).

The licensees considered external events, including aircraft crashes into the facility's buildings, floods, low water levels, wind, earthquakes, volcanoes, lightning, forest fires, freezing temperatures, and physical security (intruder-initiated events). Earthquakes or seismic events (11 accidents from 10 plants), site flooding (10 accidents from 10 plants) and tornado or extreme wind (10 accidents from 9 plants) were the most commonly cited.
There is only one subgrouping of transportation-related accidents. Eight potential transportation-related accidents were discussed, ranging from transportation of low-level waste to transportation of large components, such as the reactor pressure vessel.

There were four accidents related to nonradiological, chemical releases that were found in the licensing-basis documentation. Three of the four accidents would result in an offsite release of toxic chemicals, and the fourth would result in a chemical event that would incapacitate the operator of a crane inside the plant, thus initiating a material-handling event.

I.2 Consequences of Potential Accidents

In addition to compiling a comprehensive list of accidents and malfunctions at permanently shutdown facilities, the potential offsite dose consequences were evaluated. The evaluation of dose consequences is necessary for understanding the risk to the public from these accidents. Compared to the potential consequences from an accident at an operating facility, most of the accident consequences for a permanently shutdown facility are small. This section addresses accident consequences both from the accidents obtained from NRC-sponsored research and the accidents found in the licensing documentation.

Table I-4 presents the highest doses in each of four categories of radiological accidents as obtained from licensing-basis documents. The highest doses result from postulated fuel-related accidents and radioactive-material-related accidents. All accidents that were reviewed used conservative assumptions to calculate the offsite dose. For example, some licensees analyzed accidents that considered the 100% failure of fuel by using assumptions that were non-mechanistic to determine the estimated dose.

Information obtained from licensing-basis documents for the fuel-related accidents showed that the highest doses were from the cask or heavy load handling accidents, the accidents that assumed a 100% fuel failure, and the spent fuel handling accidents. Although some of the licensing-basis documents gave calculated doses to the offsite population from the loss of water in the spent fuel pool (Maine Yankee, 2.3 mSv [0.23 rem]; Fort St. Vrain, 0.35 mSv [0.035 rem]) and from the loss of cooling capability to the spent fuel pool (Maine Yankee, 2.2E-5 mSv [0.002 mrem]), the majority of the documents stated that these accidents would

result in no appreciable offsite dose because the accident could be mitigated before offsite-dose consequences could occur.

Table I-4. Highest Offsite Doses Calculated for Postulated Accidents in Licensing-Basis Documents

Accident Description	Nuclear Plant	Offsite Whole-Body Dose, rem
Fuel-Related Accidents		
Cask drop into spent fuel pool	Haddam Neck	0 418
Loss of spent fuel pool inventory (loss of heat sink or by inadvertent siphoning)	Maine Yankee	0.23
Shipping cask or heavy load drop into fuel element storage well	La Crosse	0.186
Loss of prestressed concrete reactor vessel shielding water (after fuel has been removed)	Fort St. Vrain	0.035
100% fuel failure	Indian Point, Unit 1	0.027
Simultaneous failure of fuel assemblies	Dresden, Unit 1	0.016
Spent fuel handling accident	Humboldt Bay, Unit 3	0 013
Fuel-handling accident	Rancho Seco	0.01
Heavy load drop	Fort St. Vrain	0 007
Fuel assembly drop	Haddam Neck	0 0026
Radioactive Material-Related Accidents (Non-Fuel)		
Spent resin handling accident (exothermic reaction during dewatering)	Haddam Neck	0 96
Explosion inside vapor container	Yankee Rowe	0.44
Radioactive liquid waste system leaks and failure	Maine Yankee	0.23
Materials-handling event	Yankee Rowe	0.16
Fire	Fort St. Vrain	0.12
Fire in intermodal container of waste	Yankee Rowe	0.1
Fire in D-rings	Three Mile Island, Unit 2	0 049
Decontamination events	Yankee Rowe	0 039
Liquid radioactive waste released to lake through cracks in building (earthquake-induced)	Fermi, Unit 1	0 02364
Release of resins from makeup and purification demineralizer	Three Mile Island, Unit 2	0 02
External-Events Initiated Accidents		
Natural disaster, tornado	Fort St. Vrain	0.001
Physical security breach	Pathfinder	<0 000001
Offsite Transportation Accidents		
Reactor pressure vessel railroad accident and fire	Pathfinder	0.00014
Truck carrying radioactive waste – fire	Pathfinder	0.000005
Reactor pressure vessel drop into river during transportation by rail	Pathfinder	0.000001
Transportation accident	Three Mile Island, Unit 2	<0.000001

To convert from rem to sievert, multiply by 0 01.

In addition to the licensing-basis documents reviewed, the staff's report *Technical Study of Spent Fuel Pool Accident Risk at Decommissioning Nuclear Power Plants* report (NRC 2001) provides an analysis of the consequences of the spent fuel pool accident risk. As discussed previously, earlier analyses in NUREG/CR-4982, *Severe Accidents in Spent Fuel Pools in Support of Generic Issue 82*, (Sailor et al. 1987) and NUREG/CR-6451, *A Safety and Regulatory Assessment of Generic BWR and PWR Permanently Shutdown Nuclear Power Plants* (Travis et al. 1997) included a limited analysis of the offsite consequences of a severe spent fuel pool accident occurring up to 90 days after the last discharge of spent fuel into the spent fuel pool. These analyses showed that the likelihood of an accident that drains the spent fuel pool is very low, although the consequences of such accidents could be comparable to those for a severe reactor accident. As part of its effort to develop generic, risk-informed requirements for decommissioning, the staff performed a further analysis of the offsite radiological consequences of beyond-design-basis spent fuel pool accidents using fission product inventories at 30 and 90 days and 2, 5, and 10 years. The accident progression scenarios that lead to large radiological releases following the drainage of a spent fuel pool require many nonmechanistic assumptions. This is because the geometry of the fuel assemblies, and the air cooling flow paths, cannot be known following a major dynamic event that might drain the water from the spent fuel pool. In addition, no credit is taken for preventative or mitigative actions and large uncertainties exist in the source term and consequence calculations. Because of these uncertainties, the staff developed bounding risk curves in NUREG-1738 (NRC 2001) that capture both the frequency and consequences of a beyond-design-basis spent fuel pool drainage event. The risk curves are provided in Figures I-1 and I-2. The results of the study indicate that the risk at spent fuel pools is low and well within the Commission's Quantitative Health Objectives. The risk is low because of the very low likelihood of a zirconium fire even though the consequences from a zirconium fire could be serious.

For the "Other Radioactive Material-Related" accidents (nonfuel), the accident subgroup with the highest estimated offsite dose was 0.96-rem total effective dose equivalent (TEDE) for a spent resin handling accident. The spent resin handling accident is only slightly below the U.S. Environmental Protection Agency's Protective Action Guide (PAGs). Other associated accident scenarios included handling accidents occurring during dewatering, releases from makeup and purification demineralizers, and the dropping of liners. Other categories with significant estimated doses include accidental releases of radioactive liquid wastes, radioactive material (nonfuel) handling accidents, explosions, and fires. However, there was a significant variation in doses within each subcategory. For example, for the radioactive liquid waste release accidents, the estimated doses range from a high of 2.3 mSv (0.23 rem) TEDE for a leak in the radioactive liquid waste system (Maine Yankee) to an estimate of "no dose" for the uncontrolled liquid waste discharge via a tank pumped directly to the river (Humboldt Bay 3).

The external event accidents (aircraft crashes, forest fires, floods, freezing temperatures, low water levels, lightning, earthquakes, volcanoes, and extreme winds and tornadoes) were in all but one case determined by the licensee's analyses either to be of a very low probability of occurrence, to have no dose consequences, to have doses that were bounded by other accidents, or to have doses that were below the U.S. Environmental Protection Agency (EPA) PAGs (EPA 1991). Most of the time, it was indicated that the doses would be significantly less than the EPA PAGs. The one case where an offsite dose was calculated was a tornado event (Fort St. Vrain), which was estimated to result in a whole body, 2-hour dose of 0.0058 mSv (0.0058 rem) and an organ dose (lung) of 0.17 mSv (0.017 rem).

Doses from offsite transportation accidents were very small, ranging from a "no dose" estimate to an estimated 0.0014 mSv (0.00014 rem) for a reactor pressure vessel that was involved in a railroad accident (Pathfinder).

The accident consequences during decommissioning are somewhat time-dependent since some of the radionuclide inventory significantly decreases shortly following shutdown, and then continues to decrease at a slower rate during the entire decommissioning period. This is most pronounced for the fuel-related accidents since some of the radionuclides present in the fuel, such as iodine-131, have a significant impact on the severity of the dose, but have a short half-life and will decay to negligible amounts within a few months following shutdown.

I.3 Correlation of Activities with Potential Accidents During Decommissioning

Activities and hazards at reactor sites following permanent shutdown and defueling may be different from those routinely experienced at an operating reactor; however, there are similarities in decommissioning activities and the activities that take place during refueling and maintenance outages.
Table I-5 lists the activities that characterize the type of actions that are being taken at sites both in DECON and SAFSTOR and compares the activities to the accidents listed in Table I-3, "Comprehensive Accident List." This list of activities was obtained from documentation from the

sites that have recently completed, or have recently started, the decommissioning process. The list is divided into activities performed during DECON and SAFSTOR. The decontamination and dismantlement activities were included for those sites that are in SAFSTOR but are performing incremental decontamination and dismantlement. Under DECON, the activities are categorized as having to do with construction; decontamination; contamination control; dismantlement; removal of the vessel, internals, and other large components and systems; radioactive waste management; spent fuel pool; soil remediation;

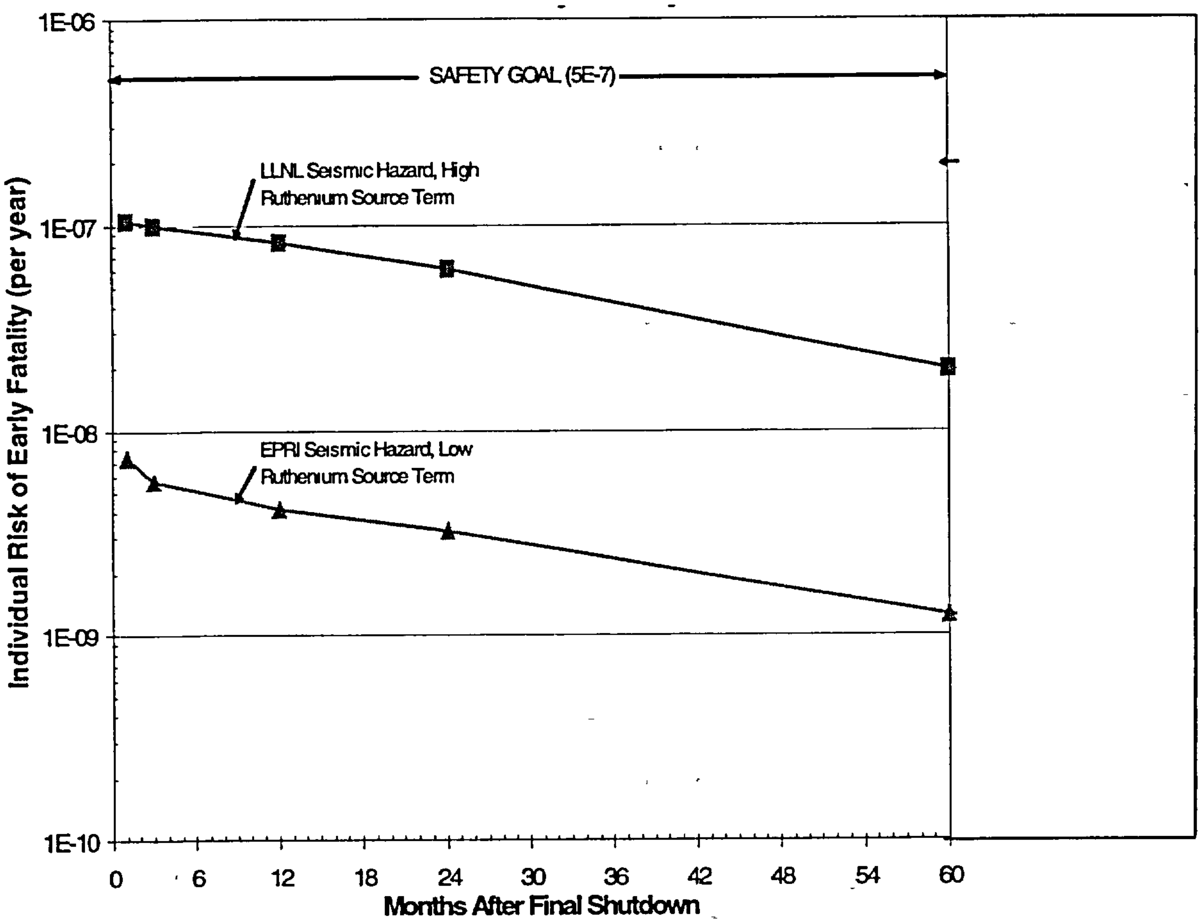

Figure I-1. Individual Early Fatality Risk Within 1 Mile of the Plant After a Beyond-Design-Basis Spent Fuel Pool Drainage Event.

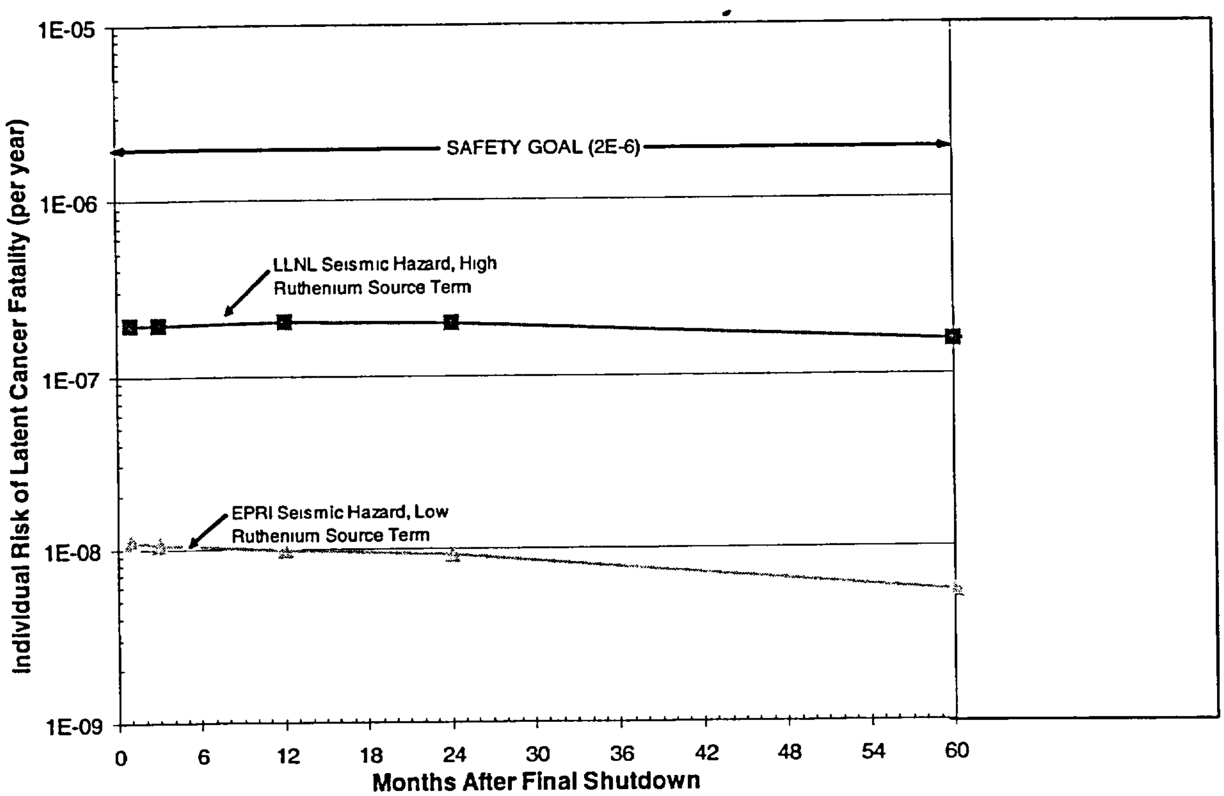

Figure I-2. Individual Latent Cancer Fatality Risk Within 10 Miles of the Plant After a Beyond-Design-Basis Spent Fuel Pool Drainage Event.

and the final radiation survey. For activities that take place during SAFSTOR, activities are simply listed as taking place in preparation for or during SAFSTOR.

For each activity, an assessment was made to determine the accident type that might occur during that activity. In the right-hand column of Table I-5, an associated accident is given, using the subgroup heading used in Table I-3. If an activity was determined not to have the potential for an accident, then it is described as "no accident." From the comparison of activities to accidents, it was determined that there would be no accident of greater consequence than the accidents already identified.

Table I-5. Comparison of Activities and Accidents During DECON and SAFSTOR

Activities	Associated Accidents
DECON	
Construction and Establishment	
Possible establishment of site construction power site	No accident
Possible establishment of monitoring stations separate from the control room	No accident
Possible construction of independent spent fuel storage installation (ISFSI)	Cask or heavy load handling
Possible establishment of spent fuel pool cooling system that is independent of existing plant systems	Loss of spent fuel cooling
Possible construction of decommissioning support building and utilities	No accident
Possible establishment of radioanalytical facilities	No accident
Possible design and fabrication of special shielding and contamination-control envelopes	No accident
Possible establishment of radiological monitoring stations	No accident
In situ chemical decontamination of primary coolant system	Decontamination-related accidents
Decontamination of outside of large components, facility surfaces, components, and piping surfaces	Decontamination-related accidents
Vacuuming	Vacuum filter bag ruptures
Ultra-high-pressure water lancing	Decontamination-related accidents
Abrasive grit blasting	Decontamination-related accidents
Manual decontamination techniques (handwriting), wet mopping, scrubbing	Decontamination-related accidents
Painting or applying coatings to stabilize contamination	No accident
Contamination Control	
Bag items to prohibit contamination spread	Fire
Dismantlement	
Remove contaminated piping and tubing - cut and install covers and plugs	Dismantlement-related accidents; fire; hazardous materials accidents
Remove walls	Radioactive material (nonfuel) handling accidents
Demolish buildings	Radioactive material (nonfuel) handling accidents
Concrete removal with impact hammers, saw cutting, and diamond wire cutting	Radioactive material (nonfuel) handling accidents
Abrasive water jet cutting (scabbier) for concrete.	Decontamination-related accidents
CO_2 blasters for concrete	Decontamination-related accidents

Table I-5. (contd)

Activities	Associated Accidents
DECON (contd)	
Metal component dismantlement - saw cutting - power band saws - diamond wire saws - machining - mechanical shearing - manual disassembly - abrasive shell cutting - OD milling machines - torch cutting (thermal methods melt or vaporize surfaces of materials being cut)	Radioactive material (nonfuel) related accidents; dismantlement-related accidents; fire; hazardous materials accidents
Rigging used to remove heavy or awkward sections Small-diameter piping	Radioactive material (nonfuel) related accidents; dismantlement-related accidents
Filings collected in catch basins and vacuumed, as needed	Radioactive material (nonfuel) related accidents; vacuum filter bag rupture
Removal of Reactor Pressure Vessel and Internals	
Piping and instrumentation lines cut; interferences removed	Radioactive material (nonfuel) related accidents; dismantlement-related accidents; fire; hazardous materials accidents
Decontaminated, segmented, packaged, and shipped offsite – segmenting included underwater semi-automatic plasma arc and metal disintegration machining equipment	Decontamination-related accidents; radioactive material (nonfuel) related accidents; dismantlement-related accidents; fire; hazardous materials accidents
Remove intact or segment	Radioactive material (nonfuel) related accidents; dismantlement-related accidents; fire; hazardous materials accidents
Intact removal requires - opening in building - grouting of openings created by cutting operations - removal from containment and placement in lay down area - removal of internals - injection of grout into reactor vessel - installation of welded closure caps on all openings - installation of structural members, as necessary - potential welding around reactor vessel.	Radioactive material (nonfuel) related accidents; dismantlement-related accidents; containment breach accidents

Table I-5. (contd)

Activities	Associated Accidents
DECON (contd)	
Removal of Other Large Components (Steam Generators and Pressurize)	
Intact removal or partial segmentation	Dismantlement-related accidents; radioactive material (nonfuel) handling accidents
Cut piping attachments	Dismantlement-related accidents; radioactive material (nonfuel) handling accidents; fire; hazardous materials accidents
Install temporary supports, cut hanger rods	No accidents given
Decontaminate external surfaces	Decontamination-related accidents
Seal-weld openings	
Move vessels horizontally for lifting through removable hatch or new opening in concrete building	Radioactive material (nonfuel) related accidents
Grout if required or segment greater than class C (GTCC) components for storage with the spent fuel	Dismantlement-related accidents; radioactive material (fuel- and nonfuel-related accidents)
Reactor Coolant System	
Decontaminate, segment, and dispose of RCS and other larger-bore piping	Radioactive material (nonfuel) related accidents; dismantlement-related accidents; fire; hazardous materials accidents
Remove and package asbestos insulation	Nonradioactive hazardous materials accidents
Remove turbine control oil	Fire
Remove nonradioactive materials, including fuel oil, lubricating oil, 1,1,1-tricholorethane, laboratory chemicals, lead, mercury, paint, battery acid, asbestos	Fire; nonradioactive hazardous materials accidents
Radwaste Management	
Ship radioactive materials	Transportation accidents
Ship mixed wastes to approved disposal sites	Transportation accidents
Spent Fuel Pool	
Remove spent fuel and GTCC waste	Cask or heavy load handling accidents; spent fuel pool handling accidents
Decontaminate and dismantle spent fuel facility after all spent fuel has been removed	Decontamination-related accidents; dismantlement-related accidents; radioactive material (nonfuel) related accidents

Table I-5. (contd)

Activities	Associated Accidents
DECON (contd)	
Soil remediation	Radioactive material (non-fuel) related accidents
Final radiation survey	No accidents
SAFSTOR	
Preparation for SAFSTOR	
Assess functional requirements for all plant systems, structures, and components for all phases of decommissioning	None
Deactivate systems; dispose of nonessential structures and systems	Radioactive material (nonfuel) related accidents; fire; hazardous materials accidents
Drain and flush plant systems	Decontamination-related accidents; hazardous materials accidents
Decontaminate, as necessary	Decontamination-related accidents
Either lay-up or isolate plant systems, structures, and components no longer required	No accidents
Remove filter elements and demineralizer resin beds	Spent resin accidents
Wet-mopping of clean areas	No accidents
Process, package, and ship liquid and solid radioactive waste generated during plant closure activities	Radioactive material (nonfuel) related accidents; radioactive liquid waste-release accidents; transportation accidents; hazardous materials accidents
Install permanent safety-related electrical power supply to spent fuel pool cooling system	Spent fuel pool cooling accidents
Establish a permanent reactor coolant system vent path (permanent passive venting of RCS to containment atmosphere)	Loss of HEPA filters; fire
Establish a permanent containment vent path	Loss of HEPA filters; fire
Removal of nitrogen gas cylinders	No accidents
Reconfigure the instrument/service air system	No accidents
Make electrical modifications required to de-energize equipment	No accidents
Remove dedicated safe-shutdown diesel and generator	Fire; hazardous materials accidents
Perform an assessment of current radiological conditions	No accidents
SAFSTOR Activities and Tasks	
24-hour guard force	No accidents
Maintain environmental and radiation monitoring program	No accidents
Preventative and corrective maintenance on operating/functional plant systems, structures, and components	No accidents
Maintain structural integrity	No accidents
Process liquid radwaste	Radioactive liquid waste releases
Provide for safe spent fuel storage	Loss of spent fuel cooling accidents

Table I-5. (contd)

Activities	Associated Accidents
SAFSTOR (contd)	
Maintain security systems	No accidents
Maintain radwaste systems	Radioactive gas waste system leaks radioactive liquid waste releases
Maintain heating and ventilation, where necessary	No accidents
Maintain lighting, fire protection, heating, ventilation, and air conditioning, and alarm systems, as required	No accidents
Dispose of nonradioactive hazardous waste	Hazardous materials accidents
Remove unused equipment during SAFSTOR	No accidents
Operate and monitor required systems	No accidents
Limited decontamination of selected structures and systems	Decontamination accidents; hazardous materials accidents
Perform general inspections during annual containment entry	No accidents

I.4 References

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I.5 Licensing Basis Documents

One of the sources of information used in this report was licensing basis documents. The sources of information listed below by nuclear facility were consulted. The documents that are listed have been docketed by the NRC and are publicly available. The docket numbers for the facilities are noted below next to the facility name.

The documents can be obtained one of three ways. First, by accessing the NRC's website the reader can obtain most of the Post-Shutdown Defueling Activities Reports (PSDARs) and License Termination Plans (LTPs) that are cited in this chapter. The address for the decommissioning page on the NRC's website is http://www.nrc.gov/OPA/reports/dcmmssng.htm.

Second, the documents can be obtained from the Public Electronic Reading Room, which provides access to the NRC's new records-management system of publicly available information the Agency wide Documents Access and Management System (ADAMS). Within this system you can access two libraries: the Publicly Available Records System, and that Public Legacy Library.

This system, which was implemented on October 12, 1999, marks a change in the previous practice where records were available only in paper or microfiche copies at either the main NRC Public Document Room in Washington, DC or at 86 local public document rooms at libraries near nuclear power plants and other regulated facilities throughout the United States. Access

to the NRC Public Electronic Reading Room will now be possible from personal computers, including those located in most public libraries.

ADAMS is an electronic information system that allows access to NRC's publicly available documents via the Internet. It permits full text searching and the ability to view document images, download files, and print locally. It also provides a more timely release of information by the NRC and faster access to documents by the public, than before. The reader can obtain the documents cited in this Appendix by providing the facility name (e.g., Trojan) or the docket number cited for each facility as shown at the end of this section, and the name or date of the document.

ADAMS can be accessed via the Internet at the NRC's website using the following URL: http://www.nrc.gov/NRC/ADAMS/index.html. This site contains instructions for installing and running ADAMS as well as information on obtaining assistance during installation or use.

The Public Electronic Reading Room on the NRC Web site at: www.nrc.gov, allows the public to use the Internet to search for any of the records that NRC has already released to the public. This site uses NRC's Agency wide Documents Access and Management System (ADAMS) to search two electronic libraries: the Public Legacy Library and the Publicly Available Records System (PARS) Library. The Public Legacy Library currently has a selection of bibliographic descriptions and some full text files of NRC records released to the public, prior to Fall 1999. Records in this library were copied from the NRC Bibliographic Retrieval System (BRS) and the Nuclear Document System (NUDOCS), the two systems previously used by the public to search for NRC records. Both BRS and NUDOCS will remain available for searching until all the records are in the Legacy Library. The other library, the Publicly Available Records System (PARS) Library, contains all NRC publicly available records released since Fall 1999. The records in the PARS Library are in, both, full text and image and the public can perform full text searches of the database, as well as view, download, and print the files from there.

Third, the NRC Public Document Room (PDR) at NRC Headquarters in Rockville, Maryland (One White Flint North, 20555 Rockville Pike, Washington DC 20555-0001 (1-800-397-4209), has a complete collection of over two million NRC documents released prior to the Fall of 1999 that are still retained as agency documents. The public may view documents at the PDR and there are reference librarians available to help in identifying, retrieving, organizing, and evaluating NRC documents from various resources and formats, including the Public Electronic Reading Room. Members of the public may also access the Electronic Reading Room libraries from computer terminals in the PDR. The PDR also provides reproduction services and, for a fee, the public can order copies of any of the records in the PDR, the Legacy, and the PARS libraries.

Big Rock Point (NRC Docket Number 50-155)

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Appendix J

Socioeconomics and Environmental Justice Impacts Related to the Decision to Permanently Cease Operations

Appendix J

Socioeconomics and Environmental Justice Impacts Related to the Decision to Permanently Cease Operations

This appendix presents information on the socioeconomic and environmental justice aspects of selected nuclear power facilities currently in the decommissioning process or that have recently completed the process. This Appendix provides a discussion of the impacts related to the decision to permanently cease operations that are outside the scope of this Supplement (See Section 1.3). The NRC staff reviewed this information to provide additional information related to concerns raised during scoping and Supplement development about Socioeconomic Impacts (Section 4.3.12) and Environmental Justice (Section 4.3.13).

Impact significance is assigned to specific issues as described in 10 CFR Part 51 Subpart A, Appendix B, Table B-1. The impacts are based on the definitions of three significance levels. Unless the significance level is identified as beneficial, the impact is adverse, or in the case of "small," may be negligible. The definitions of significance follow:

SMALL -- For the issue, environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

MODERATE -- For the issue, environmental effects are sufficient to alter noticeably, but not to destabilize, important attributes of the resource.

LARGE -- For the issue, environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.

J.1 Socioeconomic Impacts

There are two primary pathways through which the decision to permanently cease operations at a nuclear power plant creates socioeconomic impacts on the area surrounding the plant. The first is through direct expenditures in a local community by the plant work force, plus any purchases of goods and services required for plant activities. The second pathway for socioeconomic impact is through the effects on local government tax revenues and services. The impact pathways (direct expenditures and tax revenues) relate specifically to changes in the workforce and population, local tax revenues, housing availability, and public services.

Socioeconomic changes related to direct expenditures in the local community are considered not detectable if there is little or no impact on housing values, education, and other public services, and local government finances are not distinguishable from normal background variation due to other causes. Impacts on housing are considered not detectable when no discernable change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and little or no housing construction or conversion occurs. Detectable impacts result when there is a discernable increase or reduction in housing availability, rental rates and housing values exceed the inflation rate elsewhere in the State, or more than minor housing conversions and additions or abandonments occur. Destabilizing impacts occur when project-related demand results in a very large excess of housing or very limited housing availability, there are considerable increases or decreases in rental rates and housing values, and there is substantial conversion or abandonment of housing units.

Socioeconomic changes related to tax revenues and services (education, transportation, public safety, social services, public utilities, and tourism and recreation) are considered not detectable if the existing infrastructure (facilities, programs, and staff) could accommodate any changes in demand related to plant closure without a noticeable effect on the level of service. Detectable impacts arise when the changes in demand for service or use of the infrastructure is sizeable and would noticeably decrease the level of service or require additional resources to maintain the level of service. Destabilizing impacts would result when new local government programs, upgraded or new facilities, or substantial numbers of additional staff and unsupportable levels of resources are required because of facility-related demand.

The information provided here is based, in part, on data obtained from or about facilities that have completed decommissioning and facilities that are currently being decommissioned. This data was obtained in the areas of workforce and population, local tax revenues, housing availability, and public services. The time period used for was the mid-1960s to 2001.

J.1.1 Changes in Work Force and Population

The size of the work force varies considerably among operating U.S. nuclear power facilities, with the onsite staff generally consisting of 600 to 800 personnel per reactor unit. The average permanent staff size at a nuclear power facility site ranges from 800 to 2400 people, depending on the number of operating reactors at the site. In rural or low-population communities, this number of permanent jobs can provide employment for a substantial portion of the local work force. In addition to the work force needed for normal operations, many nonpermanent personnel are required for various tasks that occur during outages. Between 200 and 900 additional workers may be employed during these outages to perform the normal outage maintenance work. These are work force personnel who will be in the local community only a short time, but during these periods of extensive maintenance activities, the additional

personnel will have a substantial effect on the locality. If the local economy is stable or declining, the result of the reduction in work force related to plant closure could be economic hardships, including declining property values and business activity, and problems for local government as it adjusts to lower levels of tax revenues.

If there is a net reduction in the community work force but the economy is growing, the adverse impacts of this ongoing growth (e.g., housing shortages and school overcrowding) could be reduced. Changes of over 3 percent to a local population in a single year are expected to have detectable effects, while changes of over 5 percent are expected to result in destabilizing impacts. These negative impacts include reduction of school system enrollments, weakened housing markets, and loss of demand for goods and services provided by local business.

The impact from facility closure depends on the rate and amount of population change. If post-closure work begins shortly after shutdown with a large work force, then the impact of facility closure is mitigated. Facilities where layoffs are sudden and there is a long delay before post-closure work begins are likelier to experience negative population-related socioeconomic impacts. Thus, large plants located in rural areas that permanently shut down early and choose the SAFSTOR option are the likeliest to have negative impacts. Considering all variables such as plant size and community size as the same, plants that go into immediate DECON have fewer negative impacts that are less immediate than those of SAFSTOR. The impacts from the ENTOMB option, assuming those preparations were made immediately after shutdown, would also be less significant than those of SAFSTOR.

In only two cases did the corresponding county populations decline around the time of the closure (Indian Point, Unit 1, in Westchester, New York, and Millstone, Unit 1, in New London, Connecticut). However, during the same time period that the host counties experienced population declines, the hosting States also experienced population declines. This suggests that the decline in the county population was most likely part of an overall State population trend. Observing population trends over a decade may not capture small population declines or reductions in the rate of growth from one year to the next; however, longer trends should indicate whether or not the county had any large destabilizing population or housing impacts from the facility closure.

In 18 out of the 20 facility case studies where populations grew, the populations of the counties where the facilities are located increased more rapidly or at the same rate as the State population. The two cases where the populations of the counties grew at a slower rate include relatively rural counties in California (Humboldt and Alameda) during time periods when California as a whole experienced very high urban population growth.

Data was gathered on the changes in workforce at facilities that are currently being decommissioned (i.e., where operations have ceased), where information on operational and

decommissioning workforces was available. This information is shown in Table J-1. The table also shows the total population in the host county at the time of plant shutdown, to indicate the potential importance of the facility closure.

U.S. Census population estimates for the counties that house the closed plants are used to assess population changes around the time of shutdown by comparing percentage changes in county and State populations for the same time periods (Table J-2).

J.1.2 Local Tax Revenues

The tax revenue impacts on the local communities of plant closure vary widely from zero impact (tax-exempt plants) to a loss of 90 percent of the community tax base. The magnitude of tax-related impacts varies primarily by the size of the taxing jurisdiction and the taxing structure of the State in which the plant is sited, as well as certain plant characteristics. All else being equal, the smaller the taxing community (less economically diverse), the greater the tax-revenue impact when the nuclear facility closes down.

In communities where the revenues from the facility made up over 50 percent of the tax revenue base (with the remaining tax revenues made up primarily of private residential real estate), there were significant increases in the tax rates on the remaining real estate as well as cut-backs in services supported by property-tax revenues. The manner in which a State calculates the value of the plant also affects (a) both the amount and timing of tax losses when a nuclear power facility closes and (b) how much such a closure disrupts the tax revenue stream in a given community:

- At one plant, the assessed value of the plant was calculated as a proportional share of the value of the parent corporation, where the percentage is based on the book value of assets in the State (or sub-State taxing jurisdiction) compared with the book value of the assets of the entire corporation. This approach kept the plant at full assessed value for 7 years after its permanent closure until it was dropped from the books of the parent corporation as an asset.

- Tax rules may or may not permit gradual phase-out. In some cases, the taxable asset value of the plants was allowed to phase out over a period of time (3 to 5 years). In other cases, the plants were simply taken off the tax roles in 1 year.

Table J-1. Impact of Plant Closure on Workforce at Nuclear Power Plants Currently Being Decommissioned

Nuclear Plant	Thermal Power	Decommissioning Option[a]	Shutdown Date[b]	Maximum Workforce	Post-termination Workforce	Maximum Workforce Change	County Population
Big Rock Point	240 MW	DECON	08/30/97	--	232	--	24,496 (1997)
Dresden, Unit 1	700 MW	SAFSTOR	10/31/78	--	--	--	--
Fermi, Unit 1	200 MW	SAFSTOR[c]	09/22/72	--	--	--	--
Fort St. Vrain	842 MW	DECON[d]	08/18/89	--	--	--	--
GE-VBWR	50 MW	SAFSTOR	12/09/63	--	--	--	--
Haddam Neck	1825MW	DECON	07/22/96	--	--	--	--
Humboldt Bay, Unit 3	200 MW	SAFSTOR[c]	07/02/76	150	60	90	99,692 (1975)
Indian Point, Unit 1	615 MW	SAFSTOR	10/31/74	--	--	--	--
La Crosse	165 MW	SAFSTOR	04/30/87	82	23	59	25,965 (1987)
Maine Yankee	2700 MW	DECON	12/06/96	481	360	121	31,760 (1997)
Millstone, Unit 1	2011 MW	SAFSTOR	11/04/95	--	--	--	--
Pathfinder	190 MW	SAFSTOR[d]	09/16/67	--	--	--	--
Peach Bottom, Unit 1	115 MW	SAFSTOR	10/31/74	--	--	--	--
Rancho Seco	2772 MW	SAFSTOR[c]	06/07/89	--	200-250	--	--
San Onofre, Unit 1	1347 MW	SAFSTOR[c]	11/30/92	424	295	129	2,723,782 (1997)
Saxton	23 MW	SAFSTOR[c]	05/01/72	--	--	--	--
Shoreham	2436 MW	DECON[d]	06/28/89	–	–	–	1,303,501 (1989)
Three Mile Island, Unit 2	2772 MW	Accident cleanup, followed by storage	03/28/79	1150	125	1125	222,100 (1979)
Trojan	3411 MW	DECON	11/09/92	1319	177-432	887-1142	44,513 (1997)
Yankee Rowe	600 MW	DECON	10/01/91	--	--	--	--
Zion, Unit 1	3250 MW	SAFSTOR	02/21/97	--	--	--	--
Zion, Unit 2	3250 MW	SAFSTOR	09/19/96	--	--	--	–

(a) The option shown in the table for each plant is the option that has been officially provided to NRC. Plants in DECON may have had a short (1 to 4 yr) SAFSTOR period. Likewise, plants in SAFSTOR may have performed some DECON activities or may have transitioned from the storage phase into the decontamination and dismantlement phase of SAFSTOR.

(b) The shutdown date corresponds to the date of the last criticality.

(c) Plant has recently performed or is currently performing the decontamination and dismantlement phase of SAFSTOR.

(d) Plants has completed decommissioning

Table J-2. County and State Population Changes During Plant Closure and Decommissioning

Nuclear Plant	Reactor Type	Thermal Power	Decommissioning Option	Location	County	County Population	County Population Change, %	State Pop. Change, %
Big Rock Point	BWR	240 MW	DECON	Charlevoix, MI	Charlevoix	24,496 (1997)	6 5	1 7
Dresden, Unit 1	BWR	700 MW	SAFSTOR	Morris, IL	Grundy	28,400 (1975)	14 9	2 8
Fermi, Unit 1	FBR	200 MW	SAFSTOR	Monroe Co , MI	Monroe	126,300 (1975)	12.7	4.1
Fort St. Vrain	HTGR	842 MW	DECON	Platteville, CO	Weld	130,764 (1979)	18	18
GE-VBWR	BWR	50 MW	SAFSTOR	Alameda Co., CA	Alameda	1,071,446 (1975)	2 6	16 4
Haddam Neck	PWR	1825 MW	DECON	Haddam, CT	Middlesex	149,010 (1997)	4 1	4 2
Humboldt Bay, Unit 3	BWR	200 MW	SAFSTOR	Eureka, CA	Humboldt	99,692 (1975)	9 8	25 8
Indian Point, Unit 1	PWR	615 MW	SAFSTOR	Buchanan, NY	Westchester	874,300 (1975)	-2.7	-3 3
La Crosse	BWR	165 MW	SAFSTOR	Genoa, WI	Vernon	25,965 (1987)	6 1	5 7
Maine Yankee	PWR	2700 MW	DECON	Wiscasset, ME	Lincoln	31,760 (1997)	5 8	2 6
Millstone, Unit 1	BWR	2011 MW	SAFSTOR	Waterford, CT	New London	246,959 (1997)	-0 8	-0 5
Pathfinder	BWR	190 MW	SAFSTOR	Sioux Falls, SD	Minnehaha	95,209 (1975)	12.2	3 4
Peach Bottom, Unit 1	HTGR	115 MW	SAFSTOR	Delta, PA	York	272,603 (1975)	13 8	1
Rancho Seco	PWR	2772 MW	SAFSTOR	Sacramento, CA	Sacramento	869,581 (1989)	8.1	8 3
San Onofre, Unit 1	PWR	1347 MW	SAFSTOR	San Clemente, CA	San Diego	2,723,782 (1997)	9	8 3
Saxton	PWR	23 MW	SAFSTOR	Saxton, PA	Bedford	42,353 (1975)	10 7	1
Shoreham	BWR	2436 MW	DECON	Suffolk County, NY	Suffolk	1,303,501 (1989)	3 1	0 5
Three Mile Island, Unit 2	PWR	2772 MW	Accident cleanup, followed by storage	Middletown, PA	Dauphin	232,317 (1979)	2 4	0 2
Trojan	PWR	3411 MW	DECON	Rainier, OR	Columbia	44,513 (1997)	16 5	14 1
Yankee Rowe	PWR	600 MW	DECON	Rowe, MA	Franklin	70,626 (1997)	1 8	1.7
Zion, Unit 1	PWR	3250 MW	SAFSTOR	Zion, IL	Lake	594,799 (1997)	8 3	4 4
Zion, Unit 2	PWR	3250 MW	SAFSTOR	Zion, IL	Lake	594,799 (1997)	8 3	4 4

- The State may or may not share the burden with local government. In one State, school districts' lost property-tax collections were offset by equalization methods at the State level, which reduced the impact due to plant closures. In another State, the small neighboring township was the sole recipient of all property-tax revenues generated by the plant. Thus, the community's tax revenues were significantly reduced when the revenue source shut down.

- In addition, ratepayers in some jurisdictions are entitled to share in funds recovered from the sale of plant components and commodities and unspent decommissioning funds. These are not taxes but are available to general fund revenues.

In addition to characteristics specific to the taxing jurisdiction, the size, age, and ownership of the facilities play a role in how much the facilities affect tax revenues. Generally, the larger the facility (in the MWt), the larger the tax revenue impact. In addition, aging of the facilities depreciates its book value and assessed value over time. Usually, the falling assessed value of an aging facility will have reduced the tax revenue of the facility before closure, thus lessening the change in tax revenues generated by the facility after closure. A facility that closes suddenly, well before the end of its license expiration, will have a greater impact on the community tax base. Finally, if a facility is owned by a public entity, there is no effect on the tax base from closure because the facility was never taxable.

Changes in tax revenues of less than 10 percent are considered not detectable, i.e., they resulted in little or no change in local property tax rates and the provision of public services. Losses between 10 percent and 20 percent result in detectable impacts, with increased property tax levies (where State statutes permit) and decreased services by local municipalities. Changes over 20 percent have destabilizing impacts on the governments involved. Tax levies must usually be increased substantially or services cut substantially, and the payment of debt for any substantial infrastructure improvements made in the past becomes extremely problematic. Borrowing costs for local jurisdictions may also increase because bond rate agencies downgrade their credit rating. However, it is important to remember that these rules of thumb are based on uncompensated changes. For example, if a local taxing jurisdiction lost a nuclear facility that amounted to 35 percent of its tax base, but 30 percentage points of this loss were made up by the opening of a new manufacturing facility, the net impact would be 5 percent or not detectable. Small, rural areas are more likely to be affected than more urban areas having a wider variety of economic opportunities and more sources of tax revenue. Impacts depend on the type of plant, size of plant, and whether or not there are multiple units at a site, all of which help determine the net loss in employment at plant closure as well as the loss of tax base.

Table J-3 shows the impact of closure on local tax revenues for selected plants currently in decommissioning (or that have completed decommissioning), for which data are available. The primary taxing authorities for most of the closed plants are the county and city in which the plant is sited. Tax information is typically provided by local taxing authorities (an assessor's office) or from town planners familiar with the tax revenues generated by the plants. Only in the case of Humboldt Bay was tax-impact information available on a smaller, older plant (-$377,000 in 1983-84). The plants where information is not available are very small plants that most likely had very little impact on the tax base of the community. Many of these plants were shut down in the 1960s and 1970s.

Table J-3. Impact of Plant Closure on Local Tax Revenues

Nuclear Plant	Location	Shutdown Date	Thermal Power	Decom-missioning Option	Tax Revenues Change, millions (M)	Tax Change, %	Notes
Big Rock Point	Charlevoix, MI	08/30/97	240 MW	DECON	--	--	--
Haddam Neck	Middlesex, CT	07/22/96	1825 MW	DECON	yr 1 -$0 7M yr 2 -$0.7M yr 3 -$1.3M yr 4 -$1.2M yr 5 -$0 5M	-30% (phased out over 5 yr)	
Maine Yankee	Wiscassset, ME	12/06/96	2700 MW	DECON	yr 1 -$6 3M yr 2 -$2 5M yr 3 -$1.1M yr 4 -$0 6M	-70% (phased out in 4 yr)	Taxes paid to town. Plant made up about 90% of tax revenue. They have phased out tax expenditure payments over 6-yr period
Millstone, Unit 1	Waterford, CT	11/04/95	2011 MW	SAFSTOR	-$0 8M	-2% due to plant closure	Impacts to tax revenues in this area during this time include 1) the natural depreciation rate of Unit 1. Assessment had become less than 5% of market value of plant by time of closure (2) Deregulation environment brings assessed value of plants down 50%
Rancho Seco	Sacramento, CA	6/7/89	2772 MW	SAFSTOR	no change	0	Rancho Seco was tax-exempt because it is considered to be owned by the government. Besides sales tax, etc., no impact.
San Onofre, Unit 1	San Clemente, CA	11/30/92	1347 MW	SAFSTOR	yr 1 -$1 2M yr 2 -$1.1M yr 3 -$1.2M		
Shoreham	Suffolk Co , NY	06/28/89	2436 MW	DECON	-$10M/yr up to -$115M total change after phase-out	10% decrease in yr 1, to 60% decrease by 2003	This county was hit hard by the abrupt manner in which this plant ceased operation and the lawsuits over tax assessment that proceeded (in which a judge determines assessed value close to 0 based on projected income stream from plant).
Three Mile Island, Unit 2	Middletown, PA	03/28/79	2772 MW	Accident cleanup followed by storage	no change	0	Utilities were tax exempt in 1979.
Trojan	Rainier, OR	11/09/92	3411 MW	DECON	yr 1-7 no change yr 8 -$2 3M	7.3% reduction for the county as a whole Loss of 52 6% for one rural fire protection district.	Oregon taxes on the basis of the percentage of capital value of the parent company (ENRON) in county, based on 87% of book value of the parent in state. The Trojan "asset" stayed on ENRON's books until the year 2000.
Yankee Rowe	Rowe, MA	10/01/91	600 MW	DECON	-$0 4M	12% reduction	Rowe has a hydro-electric plant that generates most of the tax revenue (over 75%) This alleviated some of the tax impacts
Zion, Units 1 and 2	Zion, IL	02/21/97 and 09/19/96	3250 MW (each)	SAFSTOR	yr 1 -$0 4M yr 2 -$3M yr 3 -$7M	12% in yr 1, rising to 50% by yr 5 (2002)	This is an assessment of both units together. There is a phase- out approach, where assessed value is reduced from $210 M to $10 M over 8 yr

J.1.3 Housing Availability

The prevailing belief of realtors and planners in communities surrounding the case study facilities is that closing the facilities has had a range of effects on the marketability or value of homes in the vicinity. Housing choices of local residents are rarely affected by the presence of the facility, but people may move into the area in response to (temporarily) softer housing prices and commute to a nearby urban area.

J.1.4 Public Services

The impacts of closure on public services are closely related to the tax-related impacts on the community and are affected by the same characteristics of the plant: its size and age, its tax treatment, and the dependence of the local community on plant-related revenues, but not on the choice of decommissioning option or the amount of time between shutdown and active decommissioning. The impacts to the following public services may occur as a result of plant closure: education, transportation, public safety, social services, public utilities, and tourism and recreation.

Inquiries were made to local governments in the vicinity of closed plants about public service impacts during and after shutdown and decommissioning (Table J-4). Analysis was also conducted in the course of preparing NUREG-1437 (NRC 1996). Based on that experience, the following generalizations can be made.

In general, detectable impacts arise when the demand for service or use of the infrastructure is sizeable and would noticeably decrease the level of service or require additional resources to maintain the level of service. Destabilizing impacts would result when new programs, upgraded or new facilities, or substantial additional resources and staff are required because of facility-related demand.

In general, the communities that suffered the most from the tax-related impacts of plant closure also experienced the greatest impacts on public services. To some extent, the communities themselves control the amount of impact by how they allocate property taxes to local budgets before shutdown and how they prioritize these services post-shutdown. For example, one community channeled a great deal of the surplus revenues into building extensive social services for the elderly and for local youth in its community. After the plant ceased operations, the tax revenues decreased, all of the social services were downsized, and many will be eliminated because these are not considered to be priority programs (relative to public safety and education). In a second case, the county provided relatively few social services. Thus, the impact on social services after the shutdown was minor, although several other categories of

Table J-4. Impact of Plant Closure on Local Public Services

Nuclear Plant	Housing	Education	Transportation	Public Safety	Social Services	Public Utilities	Tourism and Recreation
Big Rock Point	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Dresden, Unit 1	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Fermi, Unit 1	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Fort St. Vrain	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
GE-VBWR	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Haddam Neck	SMALL to MODERATE	MODERATE	SMALL to MODERATE	MODERATE	SMALL to MODERATE	SMALL	SMALL
Humboldt Bay, Unit 3	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Indian Point, Unit 1	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
La Crosse	SMALL	SMALL to MODERATE	SMALL	SMALL to MODERATE	SMALL	SMALL	SMALL
Maine Yankee	MODERATE	MODERATE	SMALL	MODERATE	SMALL	SMALL	SMALL
Millstone, Unit 1	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Pathfinder	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Peach Bottom, Unit 1	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Rancho Seco	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
San Onofre, Unit 1	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Saxton	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Shoreham	MODERATE	MODERATE to LARGE	MODERATE	MODERATE	SMALL to MODERATE	MODERATE	SMALL
Three Mile Island, Unit 2	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Trojan	SMALL to MODERATE	MODERATE	SMALL	SMALL to MODERATE	SMALL	SMALL	SMALL
Yankee Rowe	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Zion, Unit 1	SMALL	MODERATE	MODERATE	MODERATE	MODERATE to LARGE	SMALL	SMALL
Zion, Unit 2	SMALL	MODERATE	MODERATE	MODERATE	MODERATE to LARGE	SMALL	SMALL

public service experienced larger impacts. For example, education was largely funded by plant tax revenues and the responsible school district has recently indicated that it may have to file for bankruptcy, so the impact there was substantial.[a]

(a) The size of impact can be significantly influenced by the mechanism that the State uses for funding, e.g., if the State makes up the difference between what the local school districts can fund from the local property tax and what the State has decided is the appropriate level of per-student expenditures.

In general, impacts are nondetectable and nondestabilizing if the existing infrastructure (facilities, programs, and staff) could accommodate any plant-related demand without a noticeable effect on the level of service. Detectable and nondestabilizing impacts arise when the demand for service or use of the infrastructure is sizeable and would noticeably decrease the level of service or require additional resources to maintain the level of service. Detectable and destabilizing impacts would result when new programs, upgraded or new facilities, or substantial additional staff are required because of plant-related demand. The impacts of plant closure were determined for education, transportation, public safety, social services, public utilities, and tourism and recreation.

Education: The NRC considered changes in enrollment in another licensing framework (see *The Generic Environmental Impact Statement for License Renewal of Nuclear Plants*, NUREG-1437 [NRC 1996]) that is useful in the context of plant closure. In general, nondetectable and nondestabilizing impacts are associated with project-related enrollment increases of 3 percent or less. Impacts are considered nondetectable and nondestabilizing if there is no change in the school systems' abilities to provide educational services and if no changes in the number of teaching staff or classroom space are needed. Detectable but destabilizing impacts generally are associated with 4 to 8 percent decreases in enrollment. Impacts are considered moderate if a school system must decrease its teaching staff or classroom space even slightly to preserve its pre-project level of service. Any decrease in teaching staff, however small (e.g., 0.5 full-time equivalent), that occurs from retiring or laying off personnel or changing the duties of existing personnel (e.g., a guidance counselor assuming classroom duties) may result in moderate impacts, particularly in small school systems. Detectable and destabilizing impacts are associated with project-related enrollment decreases of more than 8 percent. Some of the case-study communities had challenges adjusting to the loss of children of the plant staff from the local school systems. For example, some of the local schools had to go on a 4-day week in the Rainier, Oregon, area because loss of enrollment made the schools much more expensive to run per student served.

Transportation: The U.S. Nuclear Regulatory Commission (NRC) considered transportation issues in another licensing framework (see NUREG-1437 [NRC 1996]) that is useful in the context of plant closure. That framework considered impacts on the Transportation Research Board's level of service (LOS) definitions (Transportation Research Board 1985). LOS is a qualitative measure describing operational conditions within a traffic stream and their perception by motorists.

LOS A and B are associated with nondetectable and nondestabilizing impacts because the operation of individual users is not substantially affected by the presence of other users. At this level, no delays occur and no improvements are needed. LOS C and D are associated with detectable and nondestabilizing impacts because the operation of individual users begins to be severely restricted by other users, and at level D small increases in traffic cause operational

problems. Consequently, upgrading of roads or additional control systems may be required. LOS E and F are associated with detectable and destabilizing impacts because the use of the roadway is at or above capacity level, causing breakdowns in flow that result in long traffic delays and a potential increase in accident rates. Major renovations of existing roads or additional roads may be needed to accommodate the traffic flow.

Impacts to transportation during the license renewal term would be similar to or less than those experienced during current operations, driven mainly by the workers involved in plant closure, who are generally fewer in number than the operating staff. Consequently, LOS conditions are likely to move in the direction of A and B at all plants. Based on past and projected impacts at the case study sites, transportation impacts would continue to be nondetectable and nondestabilizing at all sites.

Public safety: Impacts on public safety are considered nondetectable and nondestabilizing if there is little or no need for additional police or fire personnel. No disruptions of police and fire-protection services occurred at the case-study sites after plant closure. Existing services were adequate to handle the influx of decommissioning staff, who are less numerous than the operations staff.

Social services: The impacts on social services are considered nondetectable and nondestabilizing if no change in the current level of service occurs, detectable and nondestabilizing if service declines noticeably, and detectable and destabilizing if services are seriously disrupted. Impacts on social services following closure largely depend on the ability of the community to replace the jobs lost at the end of operations or to successfully assist the laid-off workers and other affected workers in the community to transition out of the community. Most of the case-study sites have been able to do this, so closure impacts have been nondetectable and nondestabilizing to detectable but nondestablizing.

Public utilities: The NRC considered public utility issues in another licensing framework (see NUREG-1437 [NRC 1996]) that is useful in the context of plant closure. As in that framework, impacts on public-utility services are considered nondetectable and nondestabilizing if little or no change occurs in the ability to respond to the level of demand, and, thus, there is no need to add to capital facilities. Impacts are considered detectable and nondestabilizing if overtaxing of facilities during peak demand periods occurs. Impacts are considered detectable and destabilizing if existing service levels (such as the quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services. Overall, there have been nondetectable and nondestabilizing impacts on public utilities as a result of plant closure. The existing capacity of public utilities was sufficient to accommodate the small influx of decommissioning staff, and some locales experienced a noticeable decrease in the level of demand for services with the completion of plant operations.

Tourism and recreation: Few adverse effects have occurred during current operations at the case-study sites, and some positive effects have resulted because taxes paid by the plants and tours of the plants have also increased local tourism. Based on the case-study analysis, it is projected that because decommissioning essentially turns the operating facility back into a construction site while removing tax payments, the impacts of plant closure should be temporary, nondetectable and nondestabilizing at all plants. Some positive impact to tourism and recreation also may continue if the plant site is then converted for tourism activities, as planned for Trojan.

J.2 Environmental Justice

An evaluation of environmental justice is performed to determine if minority and low-income groups bear a disproportionate share of negative environmental consequences. Selected socioeconomic indicators are found in Table J-5 for closed nuclear power plants for which data were available. These include the median county family income as a percentage of State median family income in the year 1989, and the percentage of minority (non-white plus white Hispanic) persons in the county in the year 2000.

J.3 Reference

U. S. Nuclear Regulatory Commission (NRC). 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants.* NUREG-1437, NRC, Washington, D.C.

Table J-5. Socioeconomic Indicators Relevant to Environmental Justice at Closed Nuclear Power Plants

Nuclear Plant	Reactor Type	Decommissioning Option	Public Services Impacts	County Median Family Income (MFI), as % of State MFI[a]	Minority (Non-White and White Hispanic) in County, %[b]
Big Rock Point	BWR	DECON	SMALL	79.5	< 5
Dresden, Unit 1	BWR	SAFSTOR	SMALL	107.4	< 6
Fermi, Unit 1	FBR	SAFSTOR	SMALL	110.4	< 6
Fort St. Vrain	HTGR	DECON	SMALL	85 8	30
GE-VBWR	BWR	SAFSTOR	SMALL	110 9	59
Haddam Neck	PWR	DECON	SMALL to MODERATE	103.4	10
Humboldt Bay, Unit 3	BWR	SAFSTOR	SMALL	74 8	18
Indian Point, Unit 1	PWR	SAFSTOR	SMALL	148.3	35
La Crosse	BWR	SAFSTOR	SMALL	75.4	< 2
Maine Yankee	PWR	DECON	SMALL to MODERATE	103.1	< 2
Millstone, Unit 1	BWR	SAFSTOR	SMALL	87.9	15
Pathfinder	BWR	SAFSTOR	SMALL	124.2	< 8
Peach Bottom, Unit 1	HTGR	SAFSTOR	SMALL	107.7	< 9
Rancho Seco	PWR	SAFSTOR	SMALL	93.2	42
San Onofre, Unit 1	PWR	SAFSTOR	SMALL	128.3	45
Saxton	PWR	SAFTSOR	SMALL	72.7	< 2
Shoreham	BWR	DECON	SMALL to MODERATE	134 0	21
Three Mile Island, Unit 2	PWR	Accident cleanup, followed by storage	SMALL	106.9	24
Trojan	PWR	DECON	SMALL to MODERATE	106 5	< 7
Yankee Rowe	PWR	DECON	SMALL	82 4	< 6
Zion, Unit 1	PWR	SAFSTOR	MODERATE	135.2	26
Zion, Unit 2	PWR	SAFSTOR	MODERATE	135 2	26

(a) Source: 1990 Census of Population. *American Factfinder* Table 1990 QT. http://factfinder.census.gov
(b) Source: 2000 Census of Population. *American Factfinder* Table QT. http //factfinder census.gov

Appendix K

Transportation Impacts

Appendix K

Transportation Impacts

A generic analysis was conducted to estimate human health impacts associated with transporting decontamination and dismantlement wastes from reactor sites to low-level waste (LLW) burial grounds using the RADTRAN 4 computer code (Neuhauser and Kanipe 1992). RADTRAN was originally developed by Sandia National Laboratory to support the NUREG-0170 (NRC 1977) environment impact analysis and is commonly used for transportation impact calculations in support of environmental documentation. The more recent code, RADTRAN 5 (Neuhauser and Kanipe 1996), which uses the RADTRAN 4 models in stochastic framework, was not used because the goal of the analysis was to estimate bounds of impacts rather than a probabilistic distribution of impacts. The results of the RADTRAN 4 analysis are found in Section 4.3.17. The following is a discussion of the model input parameters.

- Waste volumes: The total volume of LLW generated during reactor decontamination and dismantlement is a function of the alternative being implemented. Waste volume estimates for decommissioning facilities were obtained for eight facilities from Post Shutdown Decommissioning Activity Reports (PSDARs), Environmental Reports (ERs), or data provided by licensees with the assistance of the Nuclear Energy Institute (NEI). Because of the small number of facilities from which estimates were obtained, the data tends to be skewed by the unique attributes of the decommissioning process for a given plant. For example, the only pressurized water reactor (PWR) facility with data for the SAFSTOR option is San Onofre, a plant that is removing all structures. The information received on LLW is summarized in Table K-1. The actual number of shipments of waste from a site during decommissioning may be inflated by State and local government regulations that require removal of all structures and concrete from the site, whether contaminated or not. For a number of sites listed in Table K-1, all waste was considered LLW, which inflated the values in the table.

  The Trojan Nuclear Plant Radiological Site Characterization Report (Trojan 1995) and the Maine Yankee License termination plan (Maine Yankee 2001) clearly show that all low-level waste is not the same. There is a relatively small volume of waste that includes the reactor vessel and internal components that has most of the residual radioactivity following cessation of operations (about 2.5-million curies). There is a slightly smaller volume of waste, such as concrete containing activation products, that contains most of the remaining residual activity (several hundred curies), and a much larger volume of waste that contains

Table K-1. Low-Level Waste Shipment Data for Decommissioning Nuclear Power Facilities

Nuclear Plant	Reactor Type	Decommissioning Option	LLW Volume, cubic meters	LLW Shipments	Distance, km (mi)
Maine Yankee	PWR	DECON	31,924 plus 853[b]	364 (truck), 181 (rail), 2 (barge)[b]	1900-4600 (1200-2860)
Haddam Neck	PWR	DECON	8017	496-582	1500-4000 (1400-2500)
Trojan	PWR	DECON	9765	470	482 (300)
San Onofre, Unit 1	PWR	SAFSTOR	--	91 (truck) 869 (rail)	--
Saxton	PWR	SAFSTOR	580	100	1000 (620)
Rancho Seco	PWR	SAFSTOR		1250 (truck) <25 (rail)	1000-4300 (620-2700)
Big Rock Point	BWR	DECON	2042	--	--
Millstone, Unit 1	BWR	SAFSTOR	18,014	--	--
Yankee Rowe[a]	PWR	DECON	4136	--	--

(a) From NUREG-1307, Rev. 9, p. A.3.
(b) Reactor pressure vessel and steam generators.

small amounts of activity (a few curies). The breakdown of LLW assumed for the evaluation of impacts of LLW transportation is shown in Table K-2.

- Number of shipments: The number of shipments was also determined from PSDARs, ERs, and data provided by NEI. These numbers represent the total number of shipments over the entire decommissioning period, which mostly occurs during decontamination and dismantlement and takes place in a period of 2-6 years. Shipment estimates were obtained for six facilities. The estimates vary significantly based on mode of transportation available at the site (truck, rail or barge), the decommissioning option chosen, the decommissioning methods being employed, the extent of facility dismantlement, and state and local requirements.

  Table K-2 includes the number of shipments estimated for each type of LLW in this analysis. The estimates were derived from the volume estimates by assuming that, on the average, each shipment of high-activity waste moved 5.3 m^3 (6.9 cubic yards) of material (capacity of a CNS 14-190 shipping cask), and each shipment of low-activity and very low-activity waste .

Table K-2. Volume and Activity Assumed for Evaluation of Radiological Impacts of Transportation of Low-Level Waste

	Total Volume, m^3 (ft^3)	Total Activity, Bq (Ci)	Activity Density, Bq/m^3 (Ci/m^3)	Shipments
High-activity waste (reactor vessel and internal components)	1200 (42,400)	9.81×10^{16} (2,650,000)	8.14×10^{13} (2200)	227
Low-activity waste (activated concrete)	750 (26,500)	1.5×10^{13} (400)	1.97×10^{10} (0.533)	84
Very low-activity waste (debris, soil)	5400 (191,00)	3.7×10^{11} (10)	6.85×10^{7} (0.0019)	360

moved 9 m^3 (12 cubic yards) of material (equivalent to 48 55-gal. drums). The reduced volume of material per shipment of the high activity waste reflects the shielding required to keep dose rates and truck weight within legal limits.

- Shipping distance: Transportation impacts and costs are a function of the distance traveled. Distances for decommissioning facilities range from 8 km (5 mi) to 4540 km (2840 mi). A bounding shipping distance of 4800 km (3000 mi) one-way was assumed for evaluation of radiological impacts of transportation; a round trip distance of 9600 km (6000 mi) was assumed for nonradiological impacts.

- Land class information: RADTRAN permits division of the transportation route into urban, suburban, and rural segments. Input to the code includes the fraction of the route that falls into each of these land-use classes, the population density in each segment, and the transport speed in each segment. Table K-3 gives the values for RADTRAN parameters used in the evaluation of LLW transport that are functions of land-use class. The percentage of the route and population density for each land-use class was estimated from routes for transport from the northeast and southeast United States to Nevada (Ramsdell et al. 2001), and the transport speeds were taken from NUREG/CR-6672 (Sprung et al. 2000). Accident rates given by Saricks and Tompkins (1999) were used in the calculations. They give the national average fatality rate for trucks as 5.5×10^{-9} fatalities per kilometer (8.8×10^{-9} fatalities per mile).

- Radiation dose rate: In calculating the doses to the public (onlookers and along the route), the radiation dose rate emitted from the shipping container was assumed to be at

Table K-3. RADTRAN Land-Use Class Dependent Parameter Values Assumed for Evaluation of Impacts of Transportation of LLW

Land-Use	Percent of Route	Population Density, people/km^2 (people/mi^2)	Transport Speed, km/h (mi/h)	Accidents per km (mi)
Urban	3	7.7 (20)	88 (55)	3.15×10^{-7} (5.07×10^{-7})
Suburban	18	390 (1000)	88 (55)	3.66×10^{-7} (5.89×10^{-7})
Rural	79	2300 (6000)	88 (55)	6.54×10^{-7} (1.05×10^{-7})

the regulatory maximum limit for transportation of high-activity waste and one-tenth of the regulatory limit for transportation of low-activity waste. The activity estimates for very low-activity waste are sufficiently small that the activity may be neglected in the evaluation of the radiological impacts of transportation of LLW. Dose rates for workers were calculated assuming 2.0×10^{-5} Sv/h (2 mrem/h).

- Radioactive material inventory: The inventory of radioactive material in a given shipment is variable. For the high-activity waste, which includes reactor vessel and internal components, the dominant radionuclides are activation products of the constituents of steel. Similarly, the dominant radionuclides in the low-activity waste are activation products of the constituents of concrete, with lesser contributions from surface contamination. Radionuclide distributions reported for residual radiation at Trojan (Trojan 1995) and Maine Yankee (Maine Yankee 2001) form the basis for the activity assumed in evaluation of the radiological impacts of LLW transport, which is shown in Table K-4. The specific isotopes for each type of LLW were selected by considering the fraction of the total activity represented by each isotope combined with the radiological consequences of exposure to the isotope. The total activity and radionuclide distributions given in these reports are generally consistent with activity and distribution estimates given in early estimates for reference reactors (Smith et al. 1978; Oak et al. 1980). RADTRAN 4 does not include nickel-63 in its library, so it was not included in the dose calculations for accidents. However, the dose is dominated by the contribution of cobalt-60 such that the dose from nickel-63 would have been negligible had it been included.

The transportation of the very low-activity waste is considered in evaluation of the nonradiological impacts of LLW transportation. In fact, most of the nonradiological impacts of transporting LLW are the result of transporting the very low-level activity because these impacts are directly associated with the number of miles driven but not with the amount of activity moved.

- Material Characterization: RADTRAN offers several default options for characterization of the dispersability of material for purposes of evaluation of the radiological consequences of transportation accidents. For this analysis, the high-activity waste was characterized as immobile because the material being transported is primarily composed of metal and the activity is primarily activation products in the metal. In an accident, 0.0001 percent of the immobile material is assumed to become airborne, and 5 percent of the airborne material is assumed to be respirable. Similarly, the low-activity waste was characterized as "loose chunks" because it tends to be concrete pieces with activation products dominating the activity. In an accident, 1 percent of the material in loose chunks is assumed to become airborne, and 5 percent of the airborne material is assumed to be respirable. These fractions, which are the RADTRAN default values, are adapted from NUREG-0170 (NRC 1977).

Table K-4. Low-Level Waste Activity Distributions Assumed for Evaluation of Radiological Impacts of LLW

	Activity Fraction		Activity per Truckload, Bq (Ci)	
	High-Activity Waste	**Low-Activity Waste**	**High-Activity Waste**	**Low-Activity Waste**
Mn-54	0.001	--	5.2×10^{11} (14)	--
Fe-55	0.348	--	1.5×10^{14} (4070)	--
Co-60	0.573	0.269	2.5×10^{14} (6680)	8.0×10^{10} (1.29)
Ni-63	0.078	--	3.4×10^{13} (920)	--
Cs-134	--	0.020	--	3.7×10^{9} (0.10)
Cs-137	--	0.010	--	1.9×10^{9} (0.05)
Eu-152	--	0.652	--	1.1×10^{11} (3.08)
Eu-154	--	0.059	--	1.0×10^{10} (0.28)

K.1 References

Maine Yankee, License No. DPR-36. January 13, 2000. Letter from George A. Zinke to U.S. Nuclear Regulatory Commission. "Maine Yankee's License Termination Plan."

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Appendix L

Relevant Regulations and Federal Permits

Appendix L

Relevant Regulations and Federal Permits

This appendix highlights the U. S. Nuclear Regulatory Commission's (NRC's) regulations and Federal statutes and regulations enacted by other Federal agencies as well as Executive Orders that are applicable to decommissioning nuclear power plants.

L.1 Applicable NRC Regulations

A brief summary of the applicable regulations of Title 10 CFR related to decommissioning are provided in this subsection. Although not a comprehensive list, this appendix briefly discusses those regulations that are most pertinent to decommissioning and were considered to be potentially of greatest interest to the reader. Licensees of facilities being decommissioned are required to continue following the regulations applicable to an operating plant unless directed otherwise by the regulations.

L.1.1 10 CFR Part 20, Standards for Protection Against Radiation

Sections of 10 CFR Part 20 establish the NRC regulations pertaining to radiological protection.

Subpart B - Radiation Protection Programs

Subpart B of 10 CFR Part 20 provides the framework for the radiation protection programs required at licensed facilities. It requires that each licensee develop and implement a radiation protection program, that the concept of keeping doses as low as reasonably achievable (ALARA) be an integral part of the program, and that the licensee annually review the program to ensure compliance with all regulations. The need for an adequate radiation protection program is essential for decommissioning plants to ensure the health and welfare of the licensee's personnel and the public.

Subpart C - Occupational Dose Limits

Subpart C of 10 CFR Part 20 provides the radiological occupational dose limits for licensee personnel and the public and the method used to demonstrate compliance with these limits.

Subpart D - Radiation Dose Limits for Individual Members of the Public

Subpart D of 10 CFR Part 20 contains the regulations that define the maximum dose limits that an individual member of the public may receive and acceptable compliance methods. These regulations are applicable for operating and decommissioning plants until license termination. Appendix B provides reference material used for determining annual limits on intake and derived air concentrations of radionuclides for occupational exposure and effluent and sewage release concentrations.

Subpart E - Radiological Criteria for License Termination

Subpart E of 10 CFR Part 20 contains the radiological criteria for license termination that apply to unrestricted and restricted use. Important aspects of the criteria include the opportunity for public participation and the assurance of adequate decommissioning funds to ensure sufficient oversight to protect public health.

Subpart F - Surveys and Monitoring

Subpart F of 10 CFR Part 20 requires surveys and monitoring commensurate with the conditions at a licensed facility. Until the license is terminated at a facility, there is a potential for radiological exposure, which would necessitate continued radiological monitoring and surveys.

Subpart G - Control of Exposure from External Sources in Restricted Areas

Subpart G of 10 CFR Part 20 requires the licensee to control access to high and very high radiation areas. These regulations are applicable to a decommissioning plant, especially in the early years of decommissioning.

Subpart H - Respiratory Protection and Controls to Restrict Internal Exposure in Restricted Areas

Subpart H of 10 CFR Part 20 requires measures to control airborne radioactive materials and the use of protective equipment to limit personnel intake.

Subpart I - Storage and Control of Licensed Material

Subpart I of 10 CFR Part 20 addresses the security and control issues related to licensed material (source material or by-product material that includes highly irradiated materials).

Subpart J - Precautionary Procedures

Subpart J of 10 CFR Part 20 defines radiological posting requirements to indicate where radiation areas are located and to label containers of licensed materials. The minimum quantities that require labeling are provided in Appendix C of 10 CFR Part 20.

Subpart K - Waste Disposal

Subpart K of 10 CFR Part 20 provides the requirements for the disposal of licensed material, including low-level waste. It provides the regulations related to manifests and manifest tracking.

Subpart L - Records

Subpart L of 10 CFR Part 20 provides requirements for recordkeeping of radiological control records. This includes individual exposure records, historical recordkeeping, and any release of radioactive effluents to the environment. Audit rectors and other reviews of the radiological control program content and implementation are required to be maintained for a period of 3 yrs, which could conceivably extend beyond the decommissioning process.

Subpart M - Reports

Subpart M of 10 CFR Part 20 provides the regulations pertaining to reporting requirements at licensed facilities. The reporting requirements contained in this subpart pertain to theft or loss of licensed materials, incident notification, radiological exposures that exceed limits, special exposures, individual overexposure, and individual monitoring. Annual personnel monitoring reports on personnel exposure are also required to be submitted.

L.1.2 10 CFR Part 50, Domestic Licensing of Production and Utilization Facilities

10 CFR 50.82, Termination of License

The current rule for decommissioning was published in August 1996 providing major changes from the previous rule. The current rule redefines the decommissioning process and requires licensees to provide the NRC with early notification of planned decommissioning activities. The rule describes the following:

- information on certifications of permanent cessation of operation and permanent removal of fuel from the plant [10 CFR 50.82(a)(1)(i), and (ii)]

- the submittal of the post-shutdown decommissioning activities report (PSDAR) (10 CFR 50.82(a)(4)(i)), which discusses the decommissioning activities and schedule for the activities, an estimate of expected costs, and the reasons for concluding that the environmental impacts associated with the site-specific decommissioning activities will be bounded by previously described environmental impacts [10 CFR 50.82(a)(4)(i)]

- the restrictions of activities of licensees performing decommissioning activities that may (a) foreclose release of the site for possible unrestricted use, (b) result in significant environmental impacts not previously reviewed, or (c) result in there no longer being reasonable assurance that adequate funds will be available for decommissioning [10 CFR 50.82(a)(6)]

- the requirement for the licensee to notify the NRC before performing any decommissioning activity inconsistent with, or making any significant schedule change from, those activities and schedules described in the PSDAR [10 CFR 50.82(a)(7)]

- how the decommissioning trust funds can be used - Withdrawals from the decommissioning trust fund can only be used [10 CFR 50.82(a)(8)(i)]

  -- if they are used for legitimate decommissioning activities that are consistent with the definition of decommissioning in 10 CFR 50.2

  -- if they do not reduce the value of the decommissioning trust below an amount necessary to place and maintain the reactor in a safe storage condition if unforeseen expenses or conditions arise

  -- if they do not inhibit the ability of the licensee to complete funding of any shortfalls in the decommissioning trust needed to ensure the availability of funds to ultimately release the site and terminate the license.

- the amount of funds available to the licensee, which varies depending on the stage of decommissioning [10 CFR 50.82(a)(8)(ii)(iii)]

  -- initially, 3 percent of the generic amount specified in 10 CFR 50.75 may be used for decommissioning planning

  -- an additional 20 percent may be used 90 days after the NRC has received the PSDAR

- -- remaining funds can be used following submittal of the site-specific decommissioning cost estimate, which is required within 2 yrs following permanent cessation of operation

- submittal of the license termination plan [10 CFR 50.82(a)(9)] and the termination of the license [10 CFR 50.82(a)(11)].

10 CFR 50.36, Technical Specifications

10 CFR 50.36(c)(6) describes requirements for technical specifications specific to decommissioning. However, the requirements of 10 CFR 50.36(a), (b) and (c) still remain applicable, as modified by paragraph (c)(6). For example, a decommissioning licensee should still evaluate paragraphs (c)(1) thru (5) regarding safety limits, limiting safety-system settings, limiting control settings, limiting conditions for operation, surveillance requirements, design features, and administrative controls; (c)(7) regarding initial notification reports; and (c)(8) regarding written reports. This is reflected by the requirement of 10 CFR 50.36(e), which states that the "provisions of this section apply to each nuclear reactor licensee whose authority to operate the reactor has been removed by license amendment, order, or regulations."

10 CFR 50.48, Fire Protection

10 CFR 50.48(f) requires that licensees of permanently shutdown nuclear power plants maintain a fire-protection program to address the potential for fires that could result in the release or spread of radioactive materials.

10 CFR 50.59, Changes, Tests, and Experiments

This section allows licensees to make changes to facilities undergoing decommissioning using these requirements.

10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants

The maintenance rule (10 CFR 50.65) requires monitoring the performance or condition of structures, systems, or components (SSCs). For licensees that have permanently ceased operation, this section applies only to the extent that the licensee shall monitor the performance or condition of SSCs associated with the storage, control, and maintenance of spent fuel. The number of SSCs within the maintenance rule program at a decommissioning facility will be significantly less than that at an operating facility.

10 CFR 50.68, Criticality Accident Requirements

This section describes the requirements that are used in lieu of maintaining a monitoring system capable of detecting a criticality in the spent fuel pool, as described in 10 CFR 70.24.

10 CFR 50.71, Inspection

This section describes the maintenance of records and making of reports. Although all paragraphs of this section are applicable, one difference between an operating facility and one being decommissioned is the requirement to update the final safety analysis report, or equivalent. As described in 10 CFR 50.71(e)(4), the decommissioning requirement is for revisions to be filed every 24 months.

10 CFR 50.73, Licensee Event Reporting System

Licensees are still required to submit a licensee event report for specific events described in the regulations within 60 days after discovery of the event. This includes airborne or liquid-effluent releases at specific levels above the concentrations in Appendix B to 10 CFR Part 20.

10 CFR 50.75, Reporting and Recordkeeping for Decommissioning Planning

Reporting and recordkeeping require that subsequent revisions updating the licensing basis must be filed with the NRC at least every 24 months by nuclear power facilities that have certified permanent cessation of operation and permanent removal of fuel for decommissioning planning. This regulation, in part, discusses how the licensee will provide reasonable assurance that funds will be available for decommissioning of the nuclear reactor.

L.1.3 10 CFR Part 71, Packaging and Transportation of Radioactive Material

Requirements for packaging, preparation for shipment, and transportation of licensed (radioactive) material are provided in these regulations. In addition, these regulations refer to the regulations of the Department of Transportation given in Title 49 of the Code of Federal Regulations.

L.1.4 10 CFR Part 72, Licensing Requirements for the Independent Storage of Spent Nuclear Fuel, High-Level Radioactive Waste, and Reactor-Related Greater Than Class C Waste

The regulations in 10 CFR Part 72 contain requirements, procedures, and criteria for the issuance of licenses to receive, transfer, and possess power-reactor spent fuel, power-reactor-related Greater-than-Class-C (GTCC) Waste, and other radioactive materials associated with spent fuel storage in an independent spent fuel storage installation and the terms and conditions under which the Commission will issue these licenses. The regulations also establish requirements, procedures, and criteria for the issuance of licenses to the U.S. Department of Energy (DOE) to receive, transfer, package, and possess power-reactor spent fuel, high-level radioactive waste, power-reactor-related GTCC waste, and other radioactive materials associated with the storage of these materials in a monitored retrievable storage installation. Finally, these regulations also establish requirements, procedures, and criteria for the issuance of Certificates of Compliance approving spent fuel storage cask designs.

L.2 Federal Statutes

Following are examples of major laws, regulations, and other requirements that may be applicable to decommissioning and environmental evaluations that occur during the decommissioning process.

American Indian Religious Freedom Act of 1978 (42 USC 1996): This act reaffirms Native American religious freedom under the First Amendment and sets United States policy to protect and preserve the inherent and constitutional right of American Indians to believe, express, and exercise their traditional religions. The act requires that Federal actions avoid interfering with access to sacred locations and traditional resources that are integral to the practice of religions.

Archaeological Resource Protection Act, as amended (16 USC 470aa et seq.): This Act requires a permit for any excavation or removal of archaeological resources from public or Indian lands. Excavations must be undertaken for the purpose of furthering archaeological knowledge in the public interest, and resources removed are to remain the property of the United States. Consent must be obtained from the Indian tribe owning lands on which a resource is located before issuance of a permit, and the permit must contain terms or conditions requested by the tribe.

Atomic Energy Act of 1954, as amended (42 USC 2011 et seq.): The Atomic Energy Act of 1954 authorizes NRC to regulate the Nation's civilian use of by-product, source, and special nuclear materials to ensure adequate protection of the public health and safety and the

DOE to establish standards to protect health or minimize dangers to life or property with respect to activities under its jurisdiction. The Atomic Energy Act and the Reorganization Plan No. 3 of 1970 [5 USC (app. at 1343)] and other related statutes gave the U.S. Environmental Protection Agency (EPA) responsibility and authority for developing generally applicable environmental standards for protection of the general environment from radioactive material. The EPA has promulgated several regulations under this authority.

Bald and Golden Eagle Protection Act, as amended (16 USC 668-668d): The Bald and Golden Eagle Protection Act makes it unlawful to take, pursue, molest, or disturb bald (American) and golden eagles, their nests, or their eggs anywhere in the United States (Section 668, 668c). A permit must be obtained from the U.S. Department of the Interior to relocate a nest that interferes with resource development or recovery operations.

Clean Air Act, as amended (42 USC 7401 et seq.): The Clean Air Act, as amended, is intended to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." Section 118 of the Clean Air Act, as amended, requires that each Federal agency, such as DOE, with jurisdiction over any property or facility that might result in the discharge of air pollutants, comply with "all Federal, state, interstate, and local requirements" with regard to the control and abatement of air pollution. The Act requires the EPA to establish National Ambient Air Quality Standards as necessary to protect public health, with an adequate margin of safety, from any known or anticipated adverse effects of a regulated pollutant (42 USC 7409). The Act also requires establishing national standards of performance for new or modified stationary sources of atmospheric pollutants (42 USC 7411) and requires specific emission increases to be evaluated so as to prevent a significant deterioration in air quality (42 USC 7470). Hazardous air pollutants, including radionuclides, are regulated separately (42 USC 7412). Air emissions are regulated by the EPA in 40 CFR Parts 50 through 99. In particular, radionuclide emissions and hazardous air pollutants are regulated under the National Emission Standard for Hazardous Air Pollutants Program (see 40 CFR Parts 61 and 63).

Clean Water Act, as amended (33 USC 1251 et seq.): The Clean Water Act, which amended the Federal Water Pollution Control Act, was enacted to "restore and maintain the chemical, physical and biological integrity of the Nation's water." The Clean Water Act prohibits the "discharge of toxic pollutants in toxic amounts" to navigable waters of the United States. Section 313 of the Clean Water Act, as amended, requires all branches of the Federal government engaged in any activity that might result in a discharge or runoff of pollutants to surface waters to comply with Federal, State, interstate, and local requirements. In addition to setting water quality standards for the nation's waterways, the Clean Water Act supplies guidelines and limitations for effluent discharges from point-source discharges and provides

authority for the EPA to implement the National Pollutant Discharge Elimination System (NPDES) permitting program. The NPDES program is administered by the Water Management Division of the EPA pursuant to regulations in 40 CFR Part 122 et seq.

Sections 401 and 405 of the Water Quality Act of 1987 added Section 402(p) to the Clean Water Act Section 402(p) requires that the Environmental Protection Act establish regulations for issuing permits for stormwater discharges associated with industrial activity. Stormwater discharges associated with industrial activity are permitted through the NPDES. General Permit requirements are published in 40 CFR Part 122.

Emergency Planning and Community Right-to-Know Act of 1986 (42 USC 11001 et seq.) (also known as SARA Title III): Under Subtitle A of this Act, Federal facilities provide various information (such as inventories of specific chemicals used or stored and releases that occur from these sites) to the State Emergency Response Commission and to the Local Emergency Planning Committee to ensure that emergency plans are sufficient to respond to unplanned releases of hazardous substances. Implementation of the provisions of this Act began voluntarily in 1987, and inventory and annual emissions reporting began in 1988, based on 1987 activities and information. The requirements for this Act were promulgated by the EPA in 40 CFR Parts 350 through 372.

Endangered Species Act, as amended (16 USC 1531 et seq.): The Endangered Species Act, as amended, is intended to prevent the further decline of endangered and threatened species and to restore these species and their habitats. The Act is jointly administered by the U.S. Departments of Commerce and the Interior. Section 7 of the Act requires consultation with the U.S. Fish and Wildlife Service to determine whether endangered and threatened species or their critical habitats are known to be in the vicinity of the proposed action.

Migratory Bird Treaty Act, as amended (10 USC 703 at seq.): The Migratory Bird Treaty Act, as amended, is intended to protect birds that have common migration patterns between the United States and Canada, Mexico, Japan, and Russia. It regulates the harvest of migratory birds by specifying the mode of harvest, hunting seasons, and bag limits. The Act stipulates that it is unlawful at any time, by any means, or in any manner to "kill ... any migratory bird." Although no permit is required under the Act, Federal agencies are required to consult with the U.S. Fish and Wildlife Service regarding impacts to migratory birds and to evaluate ways to avoid these effects in accordance with the U.S. Fish and Wildlife Service Mitigation Policy.

Native American Grave Protection and Repatriation Act of 1990 (25 USC 3001): This law directs the Secretary of Interior to guide responsibilities in repatriation of Federal archaeological collections and collections held by museums receiving Federal funding that are culturally affiliated to Native American tribes. Major actions to be taken under this law include (a) establishing

a review committee with monitoring and policy-making responsibilities, (b) developing regulations for repatriation, including procedures for identifying lineal descent or cultural affiliation needed for claims, (c) overseeing of museum programs designed to meet the inventory requirements and deadlines of this law, and (d) developing procedures to handle unexpected discoveries of graves or grave goods during activities on Federal or tribal land.

National Environmental Policy Act of 1969 as amended (42 USC 4321 et seq.): The National Environmental Policy Act (NEPA) establishes a national policy promoting awareness of the environmental consequences of the activity of humans on the environment and promoting consideration of the environmental impacts during the planning and decisionmaking stages of a project. NEPA requires all agencies of the Federal government to prepare a detailed statement on the environmental effects of proposed major Federal actions that may significantly affect the quality of the human environment. The environmental document should discuss reasonable alternatives to the proposed action and their potential environmental consequences in accordance with the Council on Environmental Quality regulations for implementing the procedural provisions of the NEPA Implementing Procedures (40 CFR Parts 1501 through 1508) and NRC implementing regulations (10 CFR Part 51).

National Historic Preservation Act, as amended (16 USC 470 et seq.): The National Historic Preservation Act, as amended, provides that sites with significant national historic value be placed on the *National Register of Historic Places.* There are no permits or certifications required under the Act. However, if a particular Federal activity may impact a historic property resource, consultation with the Advisory Council on Historic Preservation will generally generate a Memorandum of Agreement, including stipulations that must be followed to minimize adverse impacts. Coördinations with the State Historic Preservation officer are also undertaken to ensure that potentially significant sites are properly identified and appropriate mitigative actions are implemented. These regulations are included in 36 CFR Part 800. 10 CFR Part 63 contains guidance by which historic properties are evaluated and determined eligible for listing on the National Register.

Noise Control Act of 1972, as amended (42 USC 4901 et seq.): Section 4 of the Noise Control Act of 1972, as amended, directs all Federal agencies to carry out "to the fullest extent within their authority" programs within their jurisdictions in a manner that furthers a national policy of promoting an environment free from noise that jeopardizes health and welfare.

Nuclear Waste Policy Act of 1982, as amended (42 USC 10101): The Act authorizes the Federal agencies to develop a geologic repository for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The Act specifies the process for selecting a repository site and constructing, operating, closing, and decommissioning the repository. The Act also establishes programmatic guidance for these activities, including guidance to the NRC regarding the adoption of DOE's EIS for the proposed repository.

<u>Occupational Safety and Health Act of 1970, as amended (29 USC 651 et seq.)</u>: The Occupational Safety and Health Act establishes standards to enhance safe and healthful working conditions in places of employment throughout the United States. The Act is administered and enforced by the Occupational Safety and Health Administration, a U.S. Department of Labor agency. While the Occupational Safety and Health Administration and the EPA both have a mandate to reduce exposures to toxic substances, the Occupational Safety and Health Administration's jurisdiction is limited to safety and health conditions that exist in the workplace environment. In general, under the Act, it is the duty of each employer to furnish all employees a place of employment free of recognized hazards likely to cause death or serious physical harm. Employees have a duty to comply with the occupational safety and health standards and all rules, regulations, and orders issued under the Act. Occupational Safety and Health Administration regulations (published in Title 29 of the Code of Federal Regulations) establish specific standards telling employers what must be done to achieve a safe and healthful working environment.

<u>Pollution Prevention Act of 1990 (42 USC 13101 et seq.)</u>: The Pollution Prevention Act of 1990 establishes a national policy for waste management and pollution control that focuses first on source reduction, followed sequentially by environmentally safe recycling, treatment, and disposal. Disposal or releases to the environment should only occur as a last resort.

<u>Resource Conservation and Recovery Act, as amended (42 USC 6901 et seq.)</u>: The treatment, storage, or disposal of hazardous and nonhazardous waste is regulated under the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act and the Hazardous and Solid Waste Amendments of 1984. Pursuant to Section 3006 of the Act, any State that seeks to administer and enforce a hazardous waste program pursuant to the Resource Conservation and Recovery Act may apply for EPA authorization of its program. The EPA regulations implementing the Resource Conservation and Recovery Act are found in 40 CFR Parts 260 through 280. These regulations define hazardous wastes and specify hazardous waste transportation, handling, treatment, storage, and disposal requirements.

The regulations imposed on a generator or a treatment, storage, and/or disposal facility vary according to the type and quantity of material or waste generated, treated, stored, and/or disposed of. The method of treatment, storage, and/or disposal also impacts the extent and complexity of the requirements.

<u>Safe Drinking Water Act, as amended (42 USC 300 [F] et seq.)</u>: The primary objective of the Safe Drinking Water Act, as amended, is to protect the quality of the public water supplies and all sources of drinking water. The implementing regulations, administered by the EPA unless delegated to the states, establish standards applicable to public water systems. They promulgate maximum contaminant levels, including those for radioactivity, in public water systems, which are defined as public water systems that serve at least 15 service connections used by

year-round residents or regularly serve at least 25 yr-round residents. Safe Drinking Water Act requirements have been promulgated by the EPA in 40 CFR Parts 100 through 149. For radionuclides, the regulations in effect now specify that the average annual concentration of beta particle and photon radioactivity from manmade radionuclides in drinking water shall not produce an annual dose equivalent to the total body or any internal organ greater than 0.004 rem (4 millirem) per year. The maximum contaminant level for gross alpha particle activity is 15 picocuries per liter. The EPA proposed revisions to limits on regulating radionuclides on July 18, 1991. The proposed rule has not been finalized, and the more conservative standards were used for purposes of analysis. Other programs established by the Safe Drinking Water Act include the Sole Source Aquifer Program, the Wellhead Protection Program, and the Underground Injection Control Program.

Toxic Substances Control Act (15 USC 2601 et seq.): The Toxic Substances Control Act provides the EPA with the authority to require testing of chemical substances, both new and old, entering the environment and regulates them where necessary. The law complements and expands existing toxic substance laws such as §112 of the Clean Air Act and §307 of the Clean Water Act. The Toxic Substances Control Act came about because there were no general Federal regulations for the potential environmental or health effects of the thousands of new chemicals developed each year before they were introduced into the public or commerce. The Toxic Substances Control Act also regulates the treatment, storage, and disposal of toxic substances, specifically polychlorinated biphenyls, chlorofluorocarbons, asbestos, dioxins, certain metal-working fluids, and hexavalent chromium. The asbestos regulations under the Toxic Substances Control Act were ultimately overturned. However, regulations pertaining to asbestos removal, storage, and disposal are promulgated through the National Emission Standard for Hazardous Air Pollutants Program (40 CFR Part 61, Subpart M). For chlorofluorocarbons, Title VI of the Clean Air Act Amendments of 1990 requires a reduction of chlorofluorocarbons beginning in 1991 and prohibits production beginning in 2000.

L.3 Executive Orders

During the history of NEPA implementation, a number of Executive Orders have been issued that may be applicable to environmental evaluation during the decommissioning process. The following provides a short summary of some of these Orders.

Executive Order 11988 (Floodplain Management): Directs Federal agencies to establish procedures to ensure that the potential effects of flood hazards and floodplain management are considered for any action undertaken in a floodplain and that floodplain impacts be avoided to the extent practicable.

Executive Order 11990 (Protection of Wetlands): Directs government agencies to avoid, to the extent practicable, any short- and long-term adverse impacts on wetlands wherever there is a practicable alternative.

Executive Order 12898 (Environmental Justice): Directs Federal agencies to achieve environmental justice by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations in the United States and its territories and possessions. The Order creates an Interagency Working Group on Environmental Justice and directs each Federal agency to develop strategies within prescribed time limits to identify and address environmental justice concerns. The Order further directs each Federal agency to collect, maintain, and analyze information on the race, national origin, income level, and other readily accessible and appropriate information for areas surrounding facilities or sites expected to have a substantial environmental, human health, or economic effect on the surrounding populations, when such facilities or sites become the subject of a substantial Federal environmental administrative or judicial action and to make such information publicly available.

Executive Order 13007 (Indian Sacred Sites): Directs Federal agencies to accommodate, to the extent practicable, access to and ceremonial use of Indian sacred sites by Indian religious practitioners, and avoid adversely affecting the physical integrity of these sites.

Appendix M

Glossary

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Glossary

Absorbed dose — The amount of radiation energy absorbed, especially by human tissue; measured in rads.

Absorption — The process of taking in, as when a sponge takes up water. Chemicals can be absorbed through the skin into the bloodstream and then transported to other organs. Chemicals can also be absorbed into the bloodstream after breathing or swallowing.

Acute — Occurring over a short time, usually a few minutes or hours. An acute effect happens within a short time after exposure. An acute exposure can result in short-term or long-term health effects. See Chronic.

ALARA — Acronym for "as low as reasonably achievable," i.e., making every reasonable effort to maintain exposures to ionizing radiation as far below the dose limits as practical, consistent with the purpose for which the licensed activity is undertaken and taking into account the state of technology, the economics of technological improvements and of the benefits to public health and safety, and other societal and socioeconomic considerations, and in relation to utilization of nuclear energy and licensed materials in the public interest. See 10 CFR 20.1003.

Alpha particle — A positively charged particle ejected spontaneously from the nuclei of some radioactive elements. It is identical to a helium nucleus that has a mass number of 4 and an electrostatic charge of +2. It has low penetrating power and a short range (a few centimeters in air). The most energetic alpha particle will generally fail to penetrate the dead layers of cells covering the skin and can be easily

	stopped by a sheet of paper. Alpha particles are hazardous when an alpha-emitting isotope is inside the body.
Ambient	Surrounding. Ambient air is usually outdoor air (as opposed to indoor air).
Aquifer	An underground source of water geologically contained in a layer of rock, sand, or gravel.
Background level	A typical or average level of a chemical or element in the environment. Background often refers to naturally occurring or uncontaminating levels.
Background radiation	Radiation from cosmic sources; naturally occurring radioactive materials, including radon (except as a decay product of source or special nuclear material) and global fallout as it exists in the environment from the testing of nuclear explosive devices. It does not include radiation from source, by-product, or special nuclear materials regulated by the Nuclear Regulatory Commission (NRC). The typically quoted U.S. average individual exposure from background radiation is 360 mrem per yr.
Becquerel (Bq)	The unit of radioactive decay equal to 1 disintegration per second. 37 billion (3.7×10^{10}) Bq = 1 curie (Ci).
Beta particle	A charged particle emitted from a nucleus during radioactive decay, with a mass equal to 1/1837 that of a proton. A negatively charged beta particle is identical to an electron. A positively charged beta particle is called a positron. Large amounts of beta radiation may cause skin burns. Beta-emitters are harmful if they enter the body. Beta particles may be stopped by thin sheets of metal or plastic.
Boiling water reactor (BWR)	A reactor in which water, used as both coolant and moderator, is allowed to boil in the core. The resulting steam can be used directly to drive a turbine and electrical generator, thereby producing electricity.

By-product material — Any radioactive material, tailings or wastes (except special nuclear material) that is 1) yielded in, or made radioactive by, exposure to the radiation incident to the process of producing or using special nuclear material (as in a reactor) and 2) produced by the extraction or concentration of uranium or thorium from ore. See 10 CFR 20.1003.

Calibration — The adjustment, as necessary, of a measuring device such that it responds within the required range and accuracy to known values of input.

Certified fuel-handler — A nonlicensed operator who is qualified in accordance with a fuel-handler training program approved by the NRC.

Chronic — Occurring over an extended period of time, e.g., several weeks, months, or years. See Acute.

Committed dose equivalent (CDE) — This is the dose to some specific organ or tissue that is received from an intake of radioactive material by an individual during the 50-yr period following the intake. See 10 CFR 20.1003.

Committed effective dose equivalent (CEDE) — The sum of the committed dose equivalents for a given organ or tissue multiplied by a weighting factor (W_t) expressed in units of sieverts (Sv) or rems. See 10 CFR 20.1003.

Compact — A group of two or more States formed to dispose of low-level radioactive waste on a regional basis. Forty-two States have formed nine compacts.

Contamination — Undesired radioactive material or residual radioactivity that is deposited on the surface of or inside structures, areas, objects or people in excess of acceptable levels (e.g., for a release of a site or facility for unrestricted use).

Curie (Ci) — The basic unit used to describe the intensity of radioactivity in a sample of material. The curie is equal to 37-billion (3.7×10^{10}) disintegrations per second, which is approximately the activity of 1 gram of radium. A curie is also a quantity of any radionuclide that decays at a rate of

	37-billion disintegrations per second. It is named for Marie Curie, who discovered radium in 1898.
Decommission (decommissioning)	The process of safely removing a facility from service followed by reducing residual radioactivity to a level that permits termination of the NRC license. See 10 CFR 20.1003.
DECON	An option for decommissioning in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits termination of the license shortly after cessation of operations.
Decontamination	The reduction or removal of contaminated radioactive material from a structure, area, object, or person. See 10 CFR 20.1003 and 20.1402.
Dermal	Referring to the skin. For example, dermal absorption means absorption through the skin.
Disproportionately high and adverse environmental effects	When determining whether environmental effects are disproportionately high and adverse, agencies are to consider the following three factors to the extent practicable: (a) whether there is or will be an impact on the natural or physical environment that significantly (as used by NEPA) and adversely affects a minority population, low-income population, or Indian tribe - Such effects may include ecological, cultural, human health, economic, or social impacts on minority communities, low-income communities, or Indian tribes when those impacts are interrelated to impacts on the natural or physical environment, (b) whether environmental effects are significant (as employed by NEPA) and are or may be having an adverse impact on minority populations, low-income populations, or Indian tribes that appreciably exceeds or is likely to appreciably exceed those on the general population or other appropriate comparison group, and (c) whether the environmental effects occur or would occur in a minority population, low-income population, or Indian tribe affected by cumulative or multiple adverse exposures from environ-

mental hazards.

Disproportionately high and adverse human health effects

When determining whether human health effects are disproportionately high and adverse, agencies are to consider the following three factors to the extent practicable: (a) whether the health effects, which may be measured in risks and rates, are significant (as used by NEPA), or above generally accepted norms (adverse health effects may include bodily impairment, infirmity, illness, or death), (b) whether the risk or rate of hazard exposure by a minority population, low-income population, or Indian tribe to an environmental hazard is significant (as employed by NEPA) and appreciably exceeds or is likely to appreciably exceed the risk or rate to the general population or other appropriate comparison group, and (c) whether health effects occur in a minority population, low-income population, or Indian tribe affected by cumulative or multiple adverse exposures from environmental hazards.

Dose equivalent (dose)

The product of absorbed dose in tissue multiplied by a quality factor, and then sometimes multiplied by other necessary modifying factors at the location of interest. It is expressed numerically in rems or sieverts. See 10 CFR 20.1003.

Dosimeter

A portable instrument (e.g., a film badge, thermoluminescent, or pocket dosimeter) worn by plant personnel for measuring and recording the total accumulated dose of ionizing radiation.

Dosimetry

The theory and application of the principles and techniques involved in the measurement and recording of ionizing radiation doses.

Effective half-life

The time required for a radionuclide contained in a biological system, such as a human or an animal, to reduce its activity by one-half as a combined result of radioactive decay and biological elimination.

ENTOMB	A method of decommissioning in which radioactive structures, systems, and components are encased in a structurally long-lived material, such as concrete. The entombed structure is appropriately maintained, and continued surveillance is carried out until the radioactivity decays to a level that permits termination of the license.
Exposure	Contact with a chemical or element by swallowing, breathing, or direct contact (such as through the skin or eyes). Exposure may be either short-term (acute) or long- term (chronic).
External radiation	Exposure to ionizing radiation when the radiation source is located outside the body.
Fissile material	Any material fissionable by thermal (slow) neutrons. The three primary fissile materials are uranium-233, uranium-235, and plutonium-239. Although sometimes used as a synonym for fissionable material, this term has acquired a more restricted meaning.
Fission (fissioning)	The splitting of a nucleus into at least two other nuclei and the release of a relatively large amount of energy. Two or three neutrons are usually released during this type of transformation.
Fission gases	Those fission products that exist in the gaseous state. In nuclear power reactors, this includes primarily the noble gases, such as krypton and xenon.
Fission products	The nuclei (fission fragments) formed by the fission of heavy elements, plus the nuclide formed by the fission fragments' radioactive decay.
Fissionable material	Commonly used as a synonym for fissile material, the meaning of this term has been extended to include material that can be fissioned by fast neutrons, such as uranium-238.

Fuel assembly — A cluster of fuel rods (or plates). Also called a fuel element. A reactor core is made up of many fuel assemblies.

Fuel cycle — The series of steps involved in supplying fuel for nuclear power reactors. It can include mining, milling, isotopic enrichment, fabrication of fuel elements, use in a reactor, chemical reprocessing to recover the fissionable material remaining in the spent fuel, re-enrichment of the fuel material, refabrication into new fuel elements, and waste disposal.

Fuel rod — A long, slender tube that holds fissionable material (fuel) for nuclear reactor use. Fuel rods are assembled into bundles called fuel elements or fuel assemblies, which are loaded individually into the reactor core.

Fusion reaction — A reaction in which at least one heavier, more stable nucleus is produced from two lighter, less stable nuclei. Reactions of this type are responsible for enormous releases of energy, e.g., in the energy of stars.

Gamma radiation — High-energy, short wave-length, electromagnetic radiation emitted from the nucleus. Gamma radiation frequently accompanies alpha and beta emissions and always accompanies fission. Gamma rays are very penetrating and are best stopped or shielded by dense materials, such as lead or depleted uranium. Gamma rays are similar to x-rays.

Graphite — A form of carbon, similar to the lead used in pencils, used as a moderator in some nuclear reactors.

Greenfield — One possible end state of decommissioning in which above-ground structures have been removed and efforts made to revegetate the site. Buildings may have been removed to below-grade and then covered with soil. NRC decommissioning regulations do not require a greenfield end state.

Groundwater	The supply of fresh water found beneath the earth's surface (usually in aquifers) that is often used for supplying wells and springs.
Hazardous waste	By-products of society that can pose a substantial or potential hazard to human health or the environment when improperly managed. Possesses at least one of four characteristics (ignitability, corrosivity, reactivity, or toxicity), or appears on special EPA lists.
High decommissioning activity (HDA)	The licensee is actively dismantling, decontaminating, or performing activities that contribute to site release or license termination. Includes, but is not limited to, (1) major decommissioning activities or (2) periods of decommissioning in which the aggregate of licensee activities represents a significant change in facility configuration, increase in occupational dose, curies relocated, or decommissioning cost expenditure.
Highly enriched uranium	Uranium enriched to 20 percent or greater in the isotope Uranium-235.
High-level waste (HLW)	Consists of (1) irradiated (spent) reactor fuel, (2) liquid waste resulting from the operation of the first cycle solvent extraction system, and the concentrated wastes from subsequent extraction cycles, in a facility for reprocessing irradiated reactor fuel, or (3) solids into which such liquid wastes have been converted. Primarily in the form of spent fuel discharged from commercial nuclear power reactors, HLW also includes some reprocessed HLW from defense activities, and a small quantity of reprocessed commercial HLW. See Low-level waste and Radioactive waste.
High radiation area	Any area with dose rates greater than 1 mSv (100 mrems) in 1 hour, 30 centimeters from the source or from any surface through which the ionizing radiation penetrates. Areas at licensee facilities must be posted as "high radiation areas" and access into these areas is maintained under strict control.

Hot spot The region in a radiation/contamination area in which the level of radiation/contamination is significantly greater than in neighboring regions in the area.

Ingestion Swallowing (such as eating or drinking). Ingestion of radioactive material or other contaminants can occur via contact with contaminated food, drink, utensils, cigarettes, hands, or other surfaces. After ingestion, chemicals can be absorbed into the blood and distributed throughout the body.

Inhalation Breathing. Exposure may occur from inhaling contaminants because they can be deposited in the lungs, taken into the blood, or both.

Ion (1) An atom that has too many or too few electrons, causing it to have an electrical charge, and, therefore, be chemically active (2) An electron that is not associated (in orbit) with a nucleus.

Ionizing radiation Any radiation capable of displacing electrons from atoms or molecules, thereby producing ions. Some examples are alpha, beta, gamma, x-rays, neutrons, and ultraviolet light. High doses of ionizing radiation may produce severe skin or tissue damage.

Independent spent fuel storage installation (ISFSI) A complex designed and constructed for the interim storage of spent nuclear fuel and other radioactive materials associated with spent fuel storage. The most common design for an ISFSI at this time is a concrete pad with dry casks containing spent fuel bundles.

Industrial use area An area that has been designated appropriate for industrial activities.

Irradiation Exposure to radiation.

Isotope One of two or more atoms with the same number of protons, but different numbers of neutrons in their nuclei. Thus, carbon-12, carbon-13, and carbon-14 are isotopes of the element carbon, the numbers denoting the

approximate atomic weights. Isotopes have very nearly the same chemical properties, but often different physical properties (for example, carbon-12 and carbon-13 are stable, whereas carbon-14 is radioactive).

Leaching

Residual contamination transported into the subsurface as water trickles through soils or materials that contain the contamination. The water can carry the contamination through the soil and pollute nearby groundwater or surface water.

License termination plan

The license termination plan is a document that is required by 10 CFR 50.82(a)(9). The license termination plan, submitted by the licensee at least 2 yrs before termination of the license, addresses the following items: site characterization, identification of remaining site dismantlement activities, plans for site remediation, detailed plans for final radiation surveys for release of the site, method for demonstrating compliance with the radiological criteria for license termination, updated site-specific estimate of remaining decommissioning costs, and supplement to the environmental report pursuant to 10 CFR 51.53(d). The license termination plan approval process is by license amendment.

Licensing basis

The set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The licensing basis includes the NRC regulations and appendixes, orders, license conditions, exemptions, and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2, as documented in the most recent final safety analysis report (as required by 10 CFR 50.71) and the licensee's commitments remaining in effect that were made in docketed

licensing correspondence, such as licensee responses to NRC bulletins, generic letters, and enforcement actions, required certifications and submittals, NRC safety evaluations, and licensee event reports.

Light water reactor (LWR)
A term used to describe reactors using ordinary water as coolant, including boiling water reactors (BWRs) and pressurized water reactors (PWRs), the most common types used in the United States.

Low decommissioning activity (LDA)
Periods of decommissioning when a licensee either (1) maintains their facility in a true SAFSTOR configuration or (2) incrementally dismantles, decontaminates, or decommissions structures, systems, or components at such a low rate or small volume that there are only trivial changes to facility configuration, occupational dose, curie relocation, or decommissioning cost expenditure.

Low-income population
Low-income populations in an affected area should be identified with the annual statistical poverty thresholds from the Bureau of the Census' Current Population Reports, Series P-60 on Income and Poverty. In identifying low-income populations, agencies may consider as a community either a group of individuals living in geographic proximity to one another or a set of individuals (e.g., migrant workers or Native Americans), where either type of group experiences common conditions of environmental exposure or effect.

Low-level waste (LLW)
A general term for a wide range of wastes. Industries, hospitals, research institutions, private or government laboratories, and nuclear fuel-cycle facilities (e.g., nuclear power reactors and fuel fabrication plants) using radio-active materials generate LLW as part of their normal operations. These wastes are generated in many physical and chemical forms and levels of contamination. LLW usually comprises the following material contaminated with radionuclides: rags, papers, filters, solidified liquids, ion-exchange resins, tools, equipment, discarded protective clothing, dirt, construction rubble, concrete, or piping. See High-level waste and Radioactive waste.

Major decommissioning activity For a nuclear power facility, any activity that results in permanent removal of major radioactive components, permanently modifies the structure of the containment (for PWRs, the primary containment; for BWRs, the primary and secondary containments), or results in the dismantling of components or systems for shipment containing "greater than Class C" waste (10 CFR 61.55). The licensee is precluded by regulation from conducting major decommissioning activities until 90 days after the NRC has received the Post-Shutdown Decommissioning Activities Report and the 10 CFR 50.82(a)(1) certifications have been submitted.

Major radioactive component For a nuclear power plant, this includes the reactor vessel and internals, steam generators, pressurizer, large-bore reactor coolant system piping, and other large components that are radioactive to a comparable degree.

MARSSIM The Multi-Agency Radiation Survey and Site Investigation Manual (MARSSIM), which provides detailed guidance for planning, implementing, and evaluating environmental and facility radiological surveys conducted to demonstrate compliance with dose- or risk-based regulation. The MARSSIM guidance focuses on the demonstration of compliance during the final status survey following scoping, characterization, and any necessary remedial actions.

Media Soil, water, air, plants, animals, or any other parts of the environment that can contain contaminants. Body tissues or fluids such as blood, bone or urine may also be media. The singular of "media" is "medium."

Minority Individuals who are members of the following population groups: American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic.

Minority population According to the CEQ, minority populations should be identified where either (a) the minority population of the affected area exceeds 50 percent or (b) the minority population percentage of the affected area is meaningfully

greater than the minority population percentage in the general population or other appropriate unit of geographic analysis. In identifying minority communities, agencies may consider as a community either a group of individuals living in geographic proximity to one another or a geographically dispersed/transient set of individuals (e.g., migrant workers or Native American), where either type of group experiences common conditions of environmental exposure or effect. The selection of the appropriate unit of geographic analysis may be a governing body's jurisdiction, a neighborhood, census tract, or other similar unit that is to be chosen so as not to artificially dilute or inflate the affected minority population. A minority population also exists if there is more than one minority group present and the minority percentage, as calculated by aggregating all minority persons, meets one of the above-stated thresholds. NRR adopted a standard of 20 percentage points as "meaningfully greater."

Mixed waste Mixed radioactive and hazardous waste (mixed waste). (EPA 1997)

Nuclear energy The energy liberated by a nuclear reaction (fission or fusion) or by radioactive decay.

Nuclear island The nuclear island concept is used during decommissioning as a model for reducing the focus of the safeguards and security systems to the location where the fuel is being stored. For example, if the fuel is being stored in the spent fuel pool, the focus of the safeguards are on protection of only the spent fuel pool building and not the balance of the plant.

Nuclear waste See High-level waste and Low-level waste.

Operational Area The portion of the plant site where most or all of the site activities occur, such as reactor operations, materials and equipment storage, parking, substation operation, facility service and maintenance, etc. This includes all areas within the protected area fence, the intake and discharge structures, the cooling system, and other site structures,

as well as associated paved, graveled, and maintained landscaped areas.

Partial site release

The release of a portion of an operating or decommissioning nuclear power reactor facility site for unrestricted use. The licensee maintains a license for the remainder of the site. At this time there is a proposed rulemaking to change the regulations to specifically address the criteria for a partial site release. The rulemaking ensures that any remaining residual radioactivity from licensed activities in parts of a site released fro unrestricted use will meet the radiological criteria for license termination. For more detail, see the text in Chapter 3.

Permanent cessation of power operations

The permanent cessation of power operations is a licensee determination certified to the NRC in writing in accordance with 10 CFR 50.82(a)(1)(i). Following this certification, the licensee would possess the power reactor structures, systems, and components, site, and related radioactive material, but be prohibited by regulation from operating the reactor.

Personnel monitoring

The use of portable survey meters to determine the amount of contamination on an individual, or the use of dosimetry to determine an individual's occupational radiation dose.

Possession-only license (POL)

A name for the license retained by a 10 CFR Part 50 licensee that was amended to reflect the permanent shutdown condition of the facility and the licensee's continued possession of nuclear fuel.

Post-operational phase

The interval between the final reactor shutdown and the licensee's certification that all fuel has been permanently removed from the reactor vessel. See 10 CFR 50.82(a)(1)(ii). During this phase, the licensee would establish safe shutdown conditions and could conduct activities to dismantle and decontaminate structures, systems, and components or place them in a storage configuration.

Post-shutdown decommissioning activities report (PSDAR)
The PSDAR is required by 10 CFR 50.82(a)(4). The licensee is required to submit a PSDAR to the NRC within two yrs after permanent cessation of operations. Includes a description of the planned decommissioning activities, a schedule for the completion of these activities, an estimate of expected costs, and a discussion that provides the reasons for concluding that the environmental impacts associated with the site-specific decommissioning activities will be bounded by appropriate environmental impact statements previously issued.

Pressurized water reactor (PWR)
A power reactor in which heat is transferred from the core to an exchanger by high-temperature water kept under high pressure in the primary system. Steam is generated in a secondary circuit. Many reactors producing electric power are PWRs.

Previously disturbed area
An area that has been physically moved, uncovered, destabilized, or otherwise modified from its undisturbed natural condition. This definition excludes areas restored to a natural state, such that vegetative ground cover and soil characteristics that are similar to adjacent or nearby natural conditions.

Quality assurance and quality control (QA/QC)
A system of procedures, checks, and audits to judge the quality of measurements and reduce the uncertainty of environmental data.

Rad
The special unit for radiation absorbed dose, which is the amount of energy from any type of ionizing radiation (e.g., alpha, beta, gamma, neutrons, etc.) deposited in any medium (e.g., water, tissue, air). A dose of 1 rad means the absorption of 100 ergs (a small but measurable amount of energy) per gram of absorbing tissue. 100 rad = 1 gray.

Radiation
Particles (alpha, beta, neutrons) or photons (gamma) emitted from the nucleus of unstable radioactive atoms as a result of radioactive decay.

Radiation standards Exposure standards, permissible concentrations, rules for safe handling, regulations for transportation, regulations for industrial control of radiation, and control of radioactive material by legislative means.

Radioactive contamination Deposition of radioactive material in any place where it may harm persons or equipment.

Radioactive waste Solid, liquid, and gaseous materials from nuclear operations that are radioactive or become radioactive and for which there is no further use. Wastes are generally classified as high-level (having radioactivity concentrations of hundreds of thousands of curies per gallon or foot), low-level (in the range of 1 microcurie per gallon or foot), or intermediate level (between these extremes). See 10 CFR Parts 60 and 61.

Radioactivity The spontaneous emission of radiation, generally alpha or beta particles, often accompanied by gamma rays, from the nucleus of an unstable isotope. Also, the rate at which radioactive material emits radiation. Measured in units of becquerels or disintegrations per second.

Radioisotope An unstable isotope of an element that decays or disintegrates spontaneously, emitting radiation. Approximately 5000 natural and artificial radioisotopes have been identified.

Radiologically non-impacted Areas that have no reasonable potential for radioactive residual contamination are classified as non-impacted by MARSSIM (NRC 1997).

Radiological waste See "radioactive waste."

Radionuclide A radioisotope.

Reactor A device in which nuclear fission may be sustained and controlled in a self-supporting nuclear reaction. The varieties are many, but all incorporate features, such as fissionable material or fuel, a moderating material (unless the reactor is operated on fast neutrons), a reflector to conserve escaping neutrons, provisions for removal of

heat, measuring and controlling instruments, and protective devices. The reactor is the heart of a nuclear power plant.

Real property — Includes land, improvements on the land, or both, including interests therein. All equipment or fixtures (e.g., plumbing, electrical, heating, built-in cabinets, and elevators) that are installed in a building in more or less permanent manner or that are essential to its primary purpose.

Reference man — A hypothetical person with the anatomical and physiological characteristics of an average individual, used in calculations assessing internal dose (also may be called "standard man").

rem — A conventional standard unit that measures the effects of ionizing radiation on humans. The international system (SI) equivalent unit is the sievert.

Restricted use — A category of use of the facility after license termination. In restricted use, a licensee has demonstrated that further reductions in residual radioactivity would result in net public or environmental harm or that residual levels are as low as reasonably achievable, and that the licensee has made provisions for legally enforceable institutional controls (e.g., restrictions placed in the deed for the property describing what the land can and cannot be used for) that provide reasonable assurance that the radiological criteria set by the NRC will not be exceeded. In addition, the licensee must have provided sufficient financial assurance to an amenable independent third party to assume and carry out responsibilities for any necessary control and maintenance of the site. There are also regulations relating to the documentation of how the advice of individuals and institutions in the community who may be affected by the decommissioning has been sought and incorporated in the license termination plan related to decommissioning by unrestricted use.

Risk

The probability of harm. For example, for a person who has measles, the risk of death is one in one million.

Roentgen (R)

A unit of exposure to ionizing radiation. It is the amount of gamma or x-rays required to produce ions resulting in a charge of 0.000258 coulombs/kilogram of air under standard conditions. Named after Wilhelm Roentgen, the German scientist who discovered x-rays in 1895.

Rubblization

The demolition of onsite concrete structures. Rubblizing these structures could result in material ranging from gravels to large concrete blocks, or a mixture of both.

Safety limit

A limit placed upon important process variables that are found to be necessary to reasonably protect the integrity of the physical barriers guarding against the uncontrolled release.

Safety-related structures, systems, and components

Nuclear plant structures, systems, and components that are relied upon to remain functional during and following design-basis events to ensure:

- the integrity of the reactor coolant pressure boundary
- the capability to shut down the reactor and maintain it in a safe shutdown condition, or
- the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the applicable guideline exposures set forth in 10 CFR 50.34(a)(1) or 10 CFR 100.11.

SAFSTOR

A method of decommissioning in which the nuclear facility is placed and maintained in a safe stable condition for a number of years until it is subsequently decontaminated and dismantled to levels that permit license termination. During SAFSTOR, a facility is left intact, but the fuel has been removed from the reactor vessel and radioactive liquids have been drained from systems and components

and then processed. Radioactive decay occurs during the SAFSTOR period, thus reducing the quantity of contaminated and radioactive material that must be disposed of during decontamination and dismantlement.

Sewage The waste and wastewater produced by residential and commercial sources and discharged into sewers.

Sewage waste By-products of society from sewer sources.

Sewer sludge Sludge produces at a Publicly Owned Treatment Works, the disposal of which is regulated under the Clean Water Act.

Sievert An international system (SI) unit that measures the effects of ionizing radiation on humans. The conventional equivalent unit is the rem.

Site characterization One of the final steps before the termination of the license. The site characterization contains a description of (1) the radiological contamination on the site before any cleanup activities associated with decommissioning took place, (2) a historical description of site operations, spills, and accidents, and (3) a map of remaining contamination levels and contamination locations. The purpose of the site characterization is to assist in planning for remediation, selection of remediation techniques, and assessment of radiological impacts and cost estimates.

Sludge A semi-solid residue from any of a number of air or water treatment processes; can be a hazardous waste.

Spent nuclear fuel Depleted fuel that has been removed from a nuclear reactor because it can no longer sustain power production (cannot effectively sustain a chain reaction) for economic or other reasons.

Target organ An organ (such as the liver or kidney) that is specifically affected by a toxic chemical.

Technical specifications (TS)	An appendix to the facility license that contains safety requirements, bases, safety limits, limiting conditions for operation, and administrative requirements to provide assurance that decommissioning can be conducted safely and in accordance with regulatory requirements. Terminology such as "defueled TSs" or "decommissioning TSs" has been used to describe technical specifications that have been amended to reflect the permanent shutdown condition of reactor.
Transfer	Includes all real estate transfers (e.g., donation, exchange, disposal, easement, lease, permit, license).
Transuranic element	An artificially made, radioactive element that has an atomic number higher than uranium in the periodic table of elements, e.g., neptunium, plutonium, americium, and others.
Transuranic waste	Material contaminated with transuranic elements that is produced primarily from reprocessing spent fuel and from use of plutonium in fabrication of nuclear weapons.
Unrestricted area	The area outside the owner-controlled portion of a nuclear facility (usually the site boundary). An area in which a person could not be exposed to radiation levels in excess of 2 mrem in any 1 hour from external sources. See 10 CFR 20.1003.
Unrestricted use	A category of facility use after license termination. Unrestricted use means that there are no restrictions on how the site may be used. The licensee is free to continue to dismantle any remaining buildings or structures, and to use the land or sell the land for any type of application.
Vapor	The gaseous form of substances that are normally in liquid or solid form.
Volatile organic compound (VOC)	An organic chemical that evaporates easily. Petroleum products such as kerosene, gasoline, and mineral spirits contain VOCs.
Weighting factor (W_t)	Multipliers of the equivalent dose to an organ or tissue used for radiation protection purposes to account for differ-

ent sensitivities of different organs and tissues to the induction of stochastic effects of radiation. See 10 CFR 20.1003.

Whole-body counter

A device used to identify and measure the radioactive material in the bodies of human beings and animals. It uses heavy shielding to keep out naturally existing background radiation and measures radiation levels with ultra sensitive radiation detectors and electronic counting equipment.

Whole-body exposure

An exposure of the body to radiation, in which the entire body, rather than an isolated part, is irradiated. Where a radioisotope is uniformly distributed throughout the body tissues, rather than being concentrated in certain parts, the irradiation can be considered as whole-body exposure.

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10. SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

This document is a final supplement to the NRC Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities (GEIS), issued in 1988 as NUREG-0586. This supplement was prepared because of the technological advances in decommissioning operations, experience gained by licensees, and changes made to NRC regulations since the 1988 GEIS. It is intended to be used to evaluate environmental impacts during the decommissioning of nuclear power reactors as residual radioactivity at the site is reduced to levels that allow for termination of the NRC license. This supplement addresses only the decommissioning of nuclear power reactors licensed by the NRC. It updates the sections of the 1988 GEIS relating to pressurized water reactors, boiling water reactors, and multiple reactor stations. It goes beyond the 1988 GEIS to consider high-temperature gas-cooled reactors and the fast breeder reactors. This document can be considered a stand-alone document and the environmental impacts described herein supercede those described in the 1988 GEIS.

The scope of this supplement is based on the decommissioning activities performed to remove radioactive materials from structures, systems, and components from the time that the licensee certifies that they have permanently ceased power operations until the license is terminated. An evaluation process was developed to determine environmental impacts from the specific activities that occur during reactor decommissioning, based on data from site visits and from licensees at reactor facilities being decommissioned. The data obtained from the sites were analyzed and then evaluated against a list of variables that defined the parameters for facilities that are currently operating but which one day will be decommissioned. This evaluation resulted in a range of impacts for each environmental issue that may be used for comparison by licensees that are or will be decommissioning their facilities. The staff has considered public comments received during scoping and on the draft in preparation of this final supplement.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*

Supplement to the Generic Environmental Impact Statement
Decommissioning
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DECON
ENTOMB
Rubblization
Site release
License termination
Environmental impacts
Post-shutdown decommissioning activities report

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Issue/Title: Pilgrim Nuclear Power Station (PNPS): Tritium in Groundwater Monitoring Wells

Topic: PNPS Updates as of February 7, 2014

Previous Plans: Routine testing results from groundwater monitoring well samples collected during the weeks of December 30, 2013 and January 13, 2014 were partially reported by Entergy. Split sample results for the weeks of December 30, 2013 and January 13, 2014 were also reported by MERL.

Table 1[1]: Week of December 30th | Table 2: Week of January 13th

Location	Date	MERL pCi/L	GEL pCi/L		Location	Date	MERL pCi/L	GEL pCi/L
MW 201	12/30/2013	NDA(300)*	**		MW 201	1/13/2014	NDA(300)*	ND(389)*
MW 202	12/30/2013	-	-		MW 202	1/13/2014	-	-
MW 202 I	12/30/2013	-	-		MW 202 I	1/13/2014	-	-
MW 203	12/30/2013	-	-		MW 203	1/13/2014	-	-
MW 204	12/30/2013	-	-		MW 204	1/13/2014	-	-
MW 205	12/30/2013	NDA(300)*	**		MW 205	1/13/2014	NDA(300)*	NDA(359)*
MW 206	12/30/2013	852	**		MW 206	1/13/2014	NDA(300)*	NDA(353)*
MW 207	12/30/2013	-	-		MW 207	1/13/2014	-	-
MW 208-S	12/30/2013	-	-		MW 208-S	1/13/2014	-	-
MW 208-I	12/30/2013	-	-		MW 208-I	1/13/2014	-	-
MW 209	12/30/2013	1,059	**		MW 209	1/13/2014	871	1,170
MW 210	12/30/2013	-	-		MW 210	1/13/2014	-	-
MW 211	12/30/2013	1,286	**		MW 211	1/13/2014	1,207	841
MW 212	12/30/2013	-	-		MW 212	1/13/2014	-	-
MW 213	12/30/2013	-	-		MW 213	1/13/2014	-	-
MW 214	12/30/2013	-	-		MW 214	1/13/2014	-	-
MW 215	12/30/2013	1,157	**		MW 215	1/13/2014	1,130	771
MW 216	12/30/2013	5,595	4,760		MW 216	1/13/2014	4,628	3,850
MW 217	12/30/2013	-	-		MW 217	1/13/2014	-	-
MW 218	12/30/2013	3,292	2,630		MW 218	1/13/2014	5,733	4,730
MW 219	12/30/2013	70,599	69,000		MW 219	1/13/2014	2,736	2,470
MW 3	12/30/2013	-	-		MW 3	1/13/2014	-	-
MW 4R	12/30/2013	483	**		MW 4R	1/13/2014	520	548
SW-boat ramp	12/30/2013	-	-		SW-boat ramp	1/13/2014	-	-
SW-intake	1/6/2014	NDA(300)*	NDA(379)*		SW-intake	1/13/2014	NDA(300)*	NDA(347)*

*** NDA = not detected at less than activity value listed**
**** Analysis pending**
- not analyzed this week

[1] PNPS screening level for tritium in groundwater monitoring wells is 3,000 pCi/L, which is 1/10th of the NRC-approved Pilgrim Offsite Dose Calculation Manual standard for tritium in non-drinking water sources. The EPA drinking water standard is 20,000 pCi/L. The nearest drinking water wells are approximately 2.5 miles from the plant.

It is important to note that due to the need to expedite analyses of samples taken after the discovery of elevated tritium detections in newly installed wells this update includes Entergy results of some samples taken in January while some Entergy results for a number of other samples taken in December are still pending.

MW205 and MW206 Trends:

MW205 and MW206 have continued to indicate historically low results for the past six months. The most recent groundwater monitoring results for MW205 reported by Entergy show no detectable tritium for the week of January13th, and results for the week of December 30th are currently being analyzed by their contract lab (the previous Entergy result for the week of December 16th indicated 496 pCi/L of tritium detected). MERL split sample results for MW205 during the weeks of December 30th and January 13th indicated no detectable tritium. Entergy groundwater monitoring results for MW206 show no detectable tritium for the week of January13th, and results for the week of December 30th are currently being analyzed by their contract lab (the previous Entergy result for the week of December 16th indicated 799 pCi/L of tritium detected). MERL split sample results for MW206 during the week of December 30th indicated 852 pCi/L of tritium detected and split sample results for the week of January 13th indicated no detectable tritium.

New Wells:

As previously described, three new wells were installed in November and December 2013. Two of these wells were installed as part of an investigation of the separation in the neutralization sump discharge line (MW218 and MW219) and the other well was a replacement well (MW4R replaced MW4). MW4 was originally installed in the 1990s to monitor a transformer oil spill and is smaller and shallower than the other groundwater monitoring wells. MW4R's width and depth are consistent with the other groundwater monitoring wells at PNPS. Newly installed wells are sampled weekly until trends in tritium levels are established and MDPH, MEMA, and Entergy agree on a sampling schedule. MDPH has provided an updated map showing the new well locations on the department's website. It should be noted that these new wells are reportedly

approximately 24 to 25 feet below ground surface with a depth to groundwater of approximately 15 to 16 feet below ground surface. As with the other groundwater wells, samples are reportedly collected from the middle of the water column using a technique that does not change the water height in the well.

MW218 Results:

MW218 is being sampled weekly, like all new wells, and results to date are as follows:

MW218 Results to Date

Date	Entergy Result (pCi/L)	MERL Result (pCi/L)
11/18/13	4,590	4,887
11/25/13	5,810	5,831
12/2/13	4,220	5,045
12/9/13	3,950	3,823
12/16/2013	3,070	3,879
12/23/2013	3,650	3,545
12/30/2013	2,630	3,292
1/6/2013	1,580	2,346
1/13/2013	4,730	5,733
1/20/2013	Pending	3,293

As previously reported, these elevated tritium levels may possibly be attributed to the separation in the neutralization sump discharge line discovered last year.

MW219 Results:

MW219 is being sampled weekly and results to date are as follows:

MW219 Results

Date	Entergy Result (pCi/L)	MERL Result (pCi/L)
12/9/2013	2,120	NA*
12/16/2013	8,480	10,499
12/23/2013	7,600	6,484
12/30/2013	69,000	70,599
1/6/2013	20,000	21,012
1/9/2013	12,200	13,764
1/13/2013	2,470	2,736
1/20/2013	Pending	2,191

*Sample collected as part of well installation procedures; not routine sampling.

MW219 is located just down-gradient from catch basin 10 (CB-10) and thus, tritium detected in MW219 may be attributed to recent permitted neutralization sump discharges that occurred through a temporary above ground line in December 2013. CB-10 is being further investigated and is the likely cause of the elevated tritium. Because there have been no additional tritium discharges since December 20th, and subsequent tritium results for MW219 have been trending lower, it appears likely that the higher levels in MW219 are attributed to the recent discharges to CB-10. Entergy has reportedly suspended any further permitted discharges of tritium through this system until investigations and remediation are complete. MW205 is down gradient of CB-10 and thus issues with CB-10 integrity may help explain past elevations in MW205 as well. MDPH will continue to monitor results for MW219 and other down-gradient wells closely.

MW4R Results:

MW4R is located near the southeast corner of the deep foundation of the reactor and turbine buildings. MR4R is up gradient of MW216 and MW206. MW4R was installed the week of November 4, 2013 and tritium results from this new well appear to be similar to historical results for MW4 (slightly above detection limits). The most recently available Entergy results indicate 548 pCi/L of tritium detected the week of January 13th, and Entergy results for the week of January 20th are currently being analyzed by their contract lab. MERL split sample results for MW4R indicated 520 pCi/L of tritium detected for the week of January 13th and 581 pCi/L of tritium detected for the week of January 20th.

Other Wells Sampled on a Weekly Basis:

MW209 and MW211 are downgradient of the area of the neutralization sump discharge line separation and are also currently being sampled weekly. The most recent Entergy results for MW209 indicated 1,170 pCi/l of tritium detected the week of January 13, 2014, and Entergy results for the week of January 20, 2014 are currently being analyzed by their contract lab. MERL split sample results for MW209 during the week of January 13, 2014 indicated 871 pCi/L of tritium, and 1,191 pCi/L of tritium detected during the week of January 20, 2014. The most recent Entergy results for MW211 indicated 841 pCi/L of tritium detected the week of January 13, 2014, and Entergy results for the week of January 20, 2014 are currently being analyzed by their contract lab. MERL split sample results for MW211 during the week of January 13, 2014 indicated 1,207 pCi/L of tritium detected, and 1,126 pCi/L of tritium detected during the week of January 20, 2014.

MW216 continues to have higher detections than most other groundwater monitoring wells on site. MW216 is just down gradient of the end of the deep foundation on the northeast corner of the turbine and reactor buildings. The most recent Entergy results for MW216 indicated 3,850 pCi/L of tritium detected the week of January 13, 2014, and Entergy results for the week of January 20, 2014 are currently being analyzed by their contract lab. MERL split sample results for MW216 indicated 4,628 pCi/L of tritium

detected the week of January 13, 2014, and 3,760 pCi/L of tritium detected the week of January 20, 2014. As noted in a previous updates, Entergy has reported that dissolved oxygen and conductivity levels routinely measured in all groundwater monitoring wells are lower for MW216 than in other wells, and they are working with their contractor to better understand what this may mean in terms of identifying a potential tritium source contributing to this well.

Other Wells Sampled on a Bi-Weekly Basis:

Entergy results for other wells (MW201 and MW215) sampled during the weeks of December 30th and January 13th were within their typical ranges detected since the groundwater monitoring for tritium began for both Entergy results that were available and MERL split sample results.

Surface Water Results:

As previously noted, no tritium has been detected in any surface water sample taken as part of the tritium in groundwater investigation since sampling began in 2010. Since the discovery of elevated tritium in MW219, both Entergy and MERL have expedited surface water samples at the location downstream of MW205 and MW219. Results to date are shown below:

Surface water downstream of MW205 Results

Date	Entergy Result (pCi/L)	MERL Result (pCi/L)
11/25/2013	NDA < 308	NDA < 300
12/9/2013	NDA < 366	NDA < 300
12/23/2013	Pending	NDA < 300
1/6/2014	NDA < 379	NDA < 300
1/13/2014	NDA < 347	NDA < 300
1/20/2014	Pending	NDA < 300

Other Activities:

MDPH and NRC staff attended a meeting with Entergy and their contractor on January 21, 2014 to review sampling results to date, and discuss groundwater investigation plans for 2014. Items discussed include three lines of investigation focused on understanding the tritium in groundwater on the east and west sides of the reactor building. These investigations are summarized below.

West of the Reactor Building (i.e., tritium detections at MW219, MW218, MW205, MW209, MW211, and MW215)

Plans for the west side involve an investigation focused on the neutralization sump discharge line separation and CB-10. Approaches discussed include: remediating the soil in the areas of the neutralization sump discharge line separation and CB-10; rerouting future neutralization sump discharges through either an entirely new line, or through the building to another permitted discharge pathway (e.g. the radwaste discharge line); and investigating the integrity of CB-10; .

East of the Reactor Building (i.e., tritium detections at MW216, and past detections at MW206)

Plans being considered for the east side involve: an investigation of the catch basins in the area of MW216 and MW206 that accept roof drain runoff; a precipitation study to determine the role of tritium washout; an evaluation of the conductivity and dissolved oxygen in MW216; an evaluation of water migration from inside the plant to groundwater via seismic gaps[2] between the reactor and turbine buildings; and an evaluation of the contribution of historic spills to the current level of tritium in groundwater.

[2] “Seismic gaps” are spaces between two foundations that allow them to move independently in a seismic event.

East and West Side Groundwater Elevation Study

> This plan involves the collection of detailed water elevation data over a 10-day period. Data were collected using ten transducers placed at ground water monitoring wells on both the east and west sides of the reactor building in November 2013 by Entergy's contractor. An evaluation of data collected in November 2013 is currently underway. In addition, Entergy has purchased three transducers that they are rotating through wells on the site to collect supplemental groundwater elevation data.

Looking Forward:

MDPH will continue to closely follow all investigational activities that are currently underway at PNPS, notably MW219 and MW216 results, tritium in groundwater investigation plans for 2014, and transducer study results.

SCE to Brief Path Forward for Fuel Transfer Operations Restart

ROSEMEAD, Calif., Nov. 28, 2018 — Southern California Edison will preview the current schedule for resuming spent nuclear fuel transfer operations at the San Onofre nuclear plant at Thursday's Community Engagement Panel **meeting** in Oceanside. Tom Palmisano, SCE vice president, will provide an overview of SCE's efforts to strengthen the spent fuel storage program, which supports the January restart timeframe SCE is working toward.

SCE has committed to not restart spent fuel transfer operations until it is satisfied all corrective actions are in place and proven effective, the public has been briefed and the Nuclear Regulatory Commission has completed its on-site inspection actions.

"We are very confident in the corrective measures we've taken to bolster our fuel transfer operations and avoid a reoccurrence of the August event," Palmisano said. "By focusing on the January timeframe that should allow SCE, and the Nuclear Regulatory Commission, to complete any remaining actions, complete essential dry runs and ensure we can proceed error-free."

Fuel transfer operations at San Onofre have been on hold since Aug. 3. At that time, during the loading of a spent fuel canister into the Cavity Enclosure Container on the dry cask storage pad, the canister became wedged near the top of the container on an inner ring that helps to guide it into place. Slings that support the canister were lowered while the canister remained wedged. At no point during the incident was there a risk to employee or public safety.

During his presentation at the CEP meeting, Palmisano will also explain the enhancements made in several key areas of fuel transfer operations, including training, oversight, procedures and additional technology to aid in canister placement. That equipment includes cameras and load cells, devices that indicate whether tension is maintained on the slings supporting the weight of the canister.

"We were given an opportunity, through this event, to stop and improve our processes. We will continually look for ways to improve those processes until the last canister is in place," Palmisano said.

To date, SCE has safely stored 29 Holtec UMAX spent nuclear fuel canisters at its on-site spent fuel storage installation. Each canister holds 37 fuel assemblies. The remaining spent nuclear fuel at San Onofre will fill 44 additional canisters. SCE should complete all fuel transfer operations in 2019.

The Community Engagement Panel meeting will also include a facilitated discussion on the Aug. 3 canister-loading event that will include questions submitted by the public.

About Southern California Edison

An Edison International (NYSE:EIX) company, Southern California Edison is one of the nation's largest electric utilities, serving a population of approximately 15 million via 5 million customer accounts in a 50,000-square-mile service area within Central, Coastal and Southern California.

Southern California Edison Statement on Spent Nuclear Fuel Canister

Media Contact: Liese Mosher, (626) 302-2255

ROSEMEAD, Calif., Aug. 10, 2018 — Southern California Edison has directed its contractor, Holtec, to take corrective actions, including additional training, after evaluating performance errors discovered during the loading of a spent nuclear fuel canister on Aug. 3 into dry cask storage at the San Onofre nuclear plant. At no point during this incident was there a risk to employee or public safety, and immediate lessons learned have already been integrated in SCE's processes.

Holtec was loading the spent fuel canister into the Cavity Enclosure Container (CEC) on the dry cask storage pad when the canister got caught on an inner ring that helps to guide it into place. There is a very snug fit in the CECs, and it is not unusual for it to take the downloading team a few manipulations to get the canister aligned appropriately.

The crew performing this work did not initially recognize that the canister had stalled while caught on the inner ring. However, SCE's oversight team determined the canister was not sitting properly, and the canister was repositioned and safely placed on the bottom of the CEC.

SCE also directed Holtec to review the incident with the fuel handling and downloading teams and discuss lessons learned regarding the potential for the canister to become wedged in the process of lowering the canisters into the storage facility prior to loading the next canister. Additional actions and training were added to the loading processes, which is part of SCE's ongoing efforts to continuously improve its work practices. SCE does this routinely to ensure it is continuously evaluating its performance, communicating with the crews and incorporating best practices — all of these steps were discussed at the **San Onofre Community Engagement Panel** meeting Thursday night.

SCE is committed to protecting the safety of the public and takes these incidents very seriously as it progresses through its **decommissioning process**. In addition to working closely with Holtec, SCE also has discussed the performance concerns with the Nuclear Regulatory Commission.

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U.S. Global Change
Research Program

Fourth National Climate Assessment

Volume II

Impacts, Risks, and Adaptation in the United States

Full report available online at: nca2018.globalchange.gov

Image credits

Front cover: *National Park Service;* **back cover:** NASA *Earth Observatory image by Joshua Stevens, using Landsat data from the U.S. Geological Survey.*

In August 2018, temperatures soared across the northwestern United States. The heat, combined with dry conditions, contributed to wildfire activity in several states and Canada. The cover shows the Howe Ridge Fire from across Lake McDonald in Montana's Glacier National Park on the night of August 12, roughly 24 hours after it was ignited by lightning. The fire spread rapidly, fueled by record-high temperatures and high winds, leading to evacuations and closures of parts of the park. The satellite image on the back cover, acquired on August 15, shows plumes of smoke from wildfires on the northwestern edge of Lake McDonald.

Wildfires impact communities throughout the United States each year. In addition to threatening individual safety and property, wildfire can worsen air quality locally and, in many cases, throughout the surrounding region, with substantial public health impacts including increased incidence of respiratory illness (Ch. 13: Air Quality, KM 2; Ch. 14: Human Health, KM 1; Ch. 26: Alaska, KM 3). As the climate warms, projected increases in wildfire frequency and area burned are expected to drive up costs associated with health effects, loss of homes and infrastructure, and fire suppression (Ch. 6: Forests, KM 1; Ch. 17: Complex Systems, Box 17.4). Increased wildfire activity is also expected to reduce the opportunity for and enjoyment of outdoor recreation activities, affecting quality of life as well as tourist economies (Ch. 7: Ecosystems, KM 3; Ch. 13: Air Quality, KM 2; Ch. 15 Tribes, KM 1; Ch. 19: Southeast, KM 3; Ch. 24: Northwest, KM 4).

Human-caused climate change, land use, and forest management influence wildfires in complex ways (Ch. 17: Complex Systems, KM 2). Over the last century, fire exclusion policies have resulted in higher fuel availability in most U.S. forests (CSSR, Ch. 8.3, KF 6). Warmer and drier conditions have contributed to an increase in the incidence of large forest fires in the western United States and Interior Alaska since the early 1980s, a trend that is expected to continue as the climate warms and the fire season lengthens (Ch. 1: Overview, Figure 1.2k; CSSR, Ch. 8.3, KF 6). The expansion of human activity into forests and other wildland areas has also increased over the past few decades. As the footprint of human settlement expands, fire risk exposure to people and property is expected to increase further (Ch. 5: Land Changes, KM 2).

Fourth National Climate Assessment

Volume II

Impacts, Risks, and Adaptation in the United States

U.S. Global Change Research Program

Full report available online at: nca2018.globalchange.gov

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NCA4

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About This Report

The National Climate Assessment

The Global Change Research Act of 1990 mandates that the U.S. Global Change Research Program (USGCRP) deliver a report to Congress and the President no less than every four years that "1) integrates, evaluates, and interprets the findings of the Program . . .; 2) analyzes the effects of global change on the natural environment, agriculture, energy production and use, land and water resources, transportation, human health and welfare, human social systems, and biological diversity; and 3) analyzes current trends in global change, both human-induced and natural, and projects major trends for the subsequent 25 to 100 years."[1]

The Fourth National Climate Assessment (NCA4) fulfills that mandate in two volumes. This report, Volume II, draws on the foundational science described in Volume I, the *Climate Science Special Report* (CSSR).[2] Volume II focuses on the human welfare, societal, and environmental elements of climate change and variability for 10 regions and 18 national topics, with particular attention paid to observed and projected risks, impacts, consideration of risk reduction, and implications under different mitigation pathways. Where possible, NCA4 Volume II provides examples of actions underway in communities across the United States to reduce the risks associated with climate change, increase resilience, and improve livelihoods.

This assessment was written to help inform decision-makers, utility and natural resource managers, public health officials, emergency planners, and other stakeholders by providing a thorough examination of the effects of climate change on the United States.

Climate Science Special Report: NCA4 Volume I

The *Climate Science Special Report* (CSSR), published in 2017, serves as the first volume of NCA4. It provides a detailed analysis of how climate change is affecting the physical earth system across the United States and provides the foundational physical science upon which much of the assessment of impacts in this report is based. The CSSR integrates and evaluates current findings on climate science and discusses the uncertainties associated with these findings. It analyzes trends in climate change, both human-induced and natural, and projects major trends to the end of this century. Projected changes in temperature, precipitation patterns, sea level rise, and other climate outcomes are based on a range of scenarios widely used in the climate research community, referred to as Representative Concentration Pathways (RCPs). As an assessment and analysis of the physical science, the CSSR provides important input to the development of other parts of NCA4 and their primary focus on the human welfare, societal, economic, and environmental elements of climate change. A summary of the CSSR is provided in Chapter 2 (Our Changing Climate) of this report; the full report can be accessed at science2017.globalchange.gov.

Report Development, Review, and Approval Process

The National Oceanic and Atmospheric Administration (NOAA) served as the administrative lead agency for the preparation of this report. A Federal Steering Committee, composed of representatives from USGCRP agencies, oversaw the report's development.

A team of more than 300 federal and nonfederal experts—including individuals from federal, state, and local governments, tribes and Indigenous communities, national laboratories, universities, and the private sector—volunteered their time to produce the assessment, with input from external stakeholders at each stage of the process. A series of regional engagement workshops reached more than 1,000 individuals in over 40 cities, while listening sessions, webinars, and public comment periods provided valuable input to the authors. Participants included decision-makers from the public and private sectors, resource and environmental managers, scientists, educators, representatives from businesses and nongovernmental organizations, and the interested public.

NCA4 Volume II was thoroughly reviewed by external experts and the general public, as well as the Federal Government (that is, the NCA4 Federal Steering Committee and several rounds of technical and policy review by the 13 federal agencies of the USGCRP). An expert external peer review of the whole report was performed by an ad hoc committee of the National Academies of Sciences, Engineering, and Medicine (NASEM).[3] Additional information on the development of this assessment can be found in Appendix 1: Report Development Process.

Sources Used in This Report

The findings in this report are based on an assessment of the peer-reviewed scientific literature, complemented by other sources (such as gray literature) where appropriate. In addition, authors used well-established and carefully evaluated observational and modeling datasets, technical input reports, USGCRP's sustained assessment products, and a suite of scenario products. Each source was determined to meet the standards of the Information Quality Act (see Appendix 2: Information in the Fourth National Climate Assessment).

Sustained Assessment Products

The USGCRP's sustained assessment process facilitates and draws upon the ongoing participation of scientists and stakeholders, enabling the assessment of new information and insights as they emerge. The USGCRP led the development of two major sustained assessment products as inputs to NCA4: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment*[4] and the *Second State of the Carbon Cycle Report*.[5] In addition, USGCRP agencies contributed products that improve the thoroughness of this assessment, including the U.S. Department of Agriculture's scientific assessment *Climate Change, Global Food Security, and the U.S. Food System*;[6] NOAA's Climate Resilience Tool Kit, Climate Explorer, and State Climate Summaries; the U.S. Environmental Protection Agency's updated economic impacts of climate change report;[7] and a variety of USGCRP indicators and scenario products that support the evaluation of climate-related risks (see Appendix 3: Data Tools and Scenario Products).

USGCRP Scenario Products

As part of the sustained assessment process, federal interagency groups developed a suite of high-resolution scenario products that span a range of plausible future changes (through at least 2100) in key environmental parameters. This new generation of USGCRP scenario products (hosted at https://scenarios.globalchange.gov) includes

- changes in average and extreme statistics of key climate variables (for example, temperature and precipitation),
- changes in local sea level rise along the entire U.S. coastline,
- changes in population as a function of demographic shifts and migration, and
- changes in land use driven by population changes.

USGCRP scenario products help ensure consistency in underlying assumptions across the report and therefore improve the ability to compare and synthesize results across chapters. Where possible, authors have used the range of these scenario products to frame uncertainty in future climate and associated effects as it relates to the risks that are the focus of their chapters. As discussed briefly elsewhere in this Front Matter and in more detail in Appendix 3 (Data Tools and Scenario Products), future scenarios referred to as RCPs provide the global framing for NCA4 Volumes I and II. RCPs focus on outputs (such as emissions and concentrations of greenhouse gases and particulate matter) that are in turn fed into climate models. As such, a wide range of future socioeconomic assumptions, at the global and national scale (such as population growth, technological innovation, and carbon intensity of energy mix), could be consistent with the RCPs used throughout NCA4. For this reason, further guidance on U.S. population and land-use assumptions was provided to authors. See Appendix 3: Data Tools and Scenario Products, including Table A3.1, for additional detail on these scenario products.

Guide to the Report

Summary Findings

The 12 Summary Findings represent a very high-level synthesis of the material in the underlying report. They consolidate Key Messages and supporting evidence from 16 underlying national-level topic chapters, 10 regional chapters, and 2 response chapters.

Overview

The Overview presents the major findings alongside selected highlights from NCA4 Volume II, providing a synthesis of material from the underlying report chapters.

Chapter Text

Key Messages and Traceable Accounts

Chapters are centered around Key Messages, which are based on the authors' expert judgment of the synthesis of the assessed literature. With a view to presenting technical information in a manner more accessible to a broad audience, this report aims to present findings in the context of risks to natural and/or human systems. Assessing the risks to the Nation posed by climate change and the measures that can be taken to minimize those risks helps users weigh the consequences of complex decisions.

Since risk can most meaningfully be defined in relation to objectives or societal values, Key Messages in each chapter of this report aim to provide answers to specific questions about what is at risk in a particular region or sector and in what way. The text supporting each Key Message provides evidence, discusses implications, identifies intersections between systems or cascading hazards, and points out paths to greater resilience. Where a Key Message focuses on managing risk, authors considered the following questions:

- What do we value? What is at risk?
- What outcomes do we wish to avoid with respect to these valued things?
- What do we expect to happen in the absence of adaptive action and/or mitigation?
- How bad could things plausibly get? Are there important thresholds or tipping points in the unique context of a given region, sector, and so on?

These considerations are encapsulated in a single question: What keeps you up at night? Importantly, climate is only one of many drivers of change and risk. Where possible, chapters provide information about the dominant sources of uncertainty (such as scientific uncertainty or socioeconomic factors), as well as information regarding other relevant non-climate stressors.

Each Key Message is accompanied by a Traceable Account that restates the Key Message found in the chapter text with calibrated confidence and likelihood language (see Table 1). These Traceable Accounts also document the supporting evidence and rationale the authors used in reaching their conclusions, while also providing information on sources of uncertainty. More information on Traceable Accounts is provided below.

Our Changing Climate

USGCRP oversaw the production of the *Climate Science Special Report* (CSSR): NCA4 Volume I,[2] which assesses the current state of science relating to climate change and its physical impacts. The CSSR is a detailed analysis of how climate change affects the physical earth system across the United States. It presents foundational information and projections for climate change that improve consistency across

analyses in NCA4 Volume II. The CSSR is the basis for the physical climate science summary presented in Chapter 2 (Our Changing Climate) of this report.

National Topic Chapters

The national topic chapters summarize current and future climate change related risks and what can be done to reduce those risks. These national chapters also synthesize relevant content from the regional chapters. New national topic chapters for NCA4 include Chapter 13: Air Quality; Chapter 16: Climate Effects on U.S. International Interests; and Chapter 17: Sector Interactions, Multiple Stressors, and Complex Systems.

Regional Chapters

Responding to public demand for more localized information—and because impacts and adaptation tend to be realized at a more local level—NCA4 provides greater detail in the regional chapters compared to the national topic chapters. The regional chapters assess current and future risks posed by climate change to each of NCA4's 10 regions (see Figure 1) and what can be done to minimize risk. Challenges, opportunities, and success stories for managing risk are illustrated through case studies.

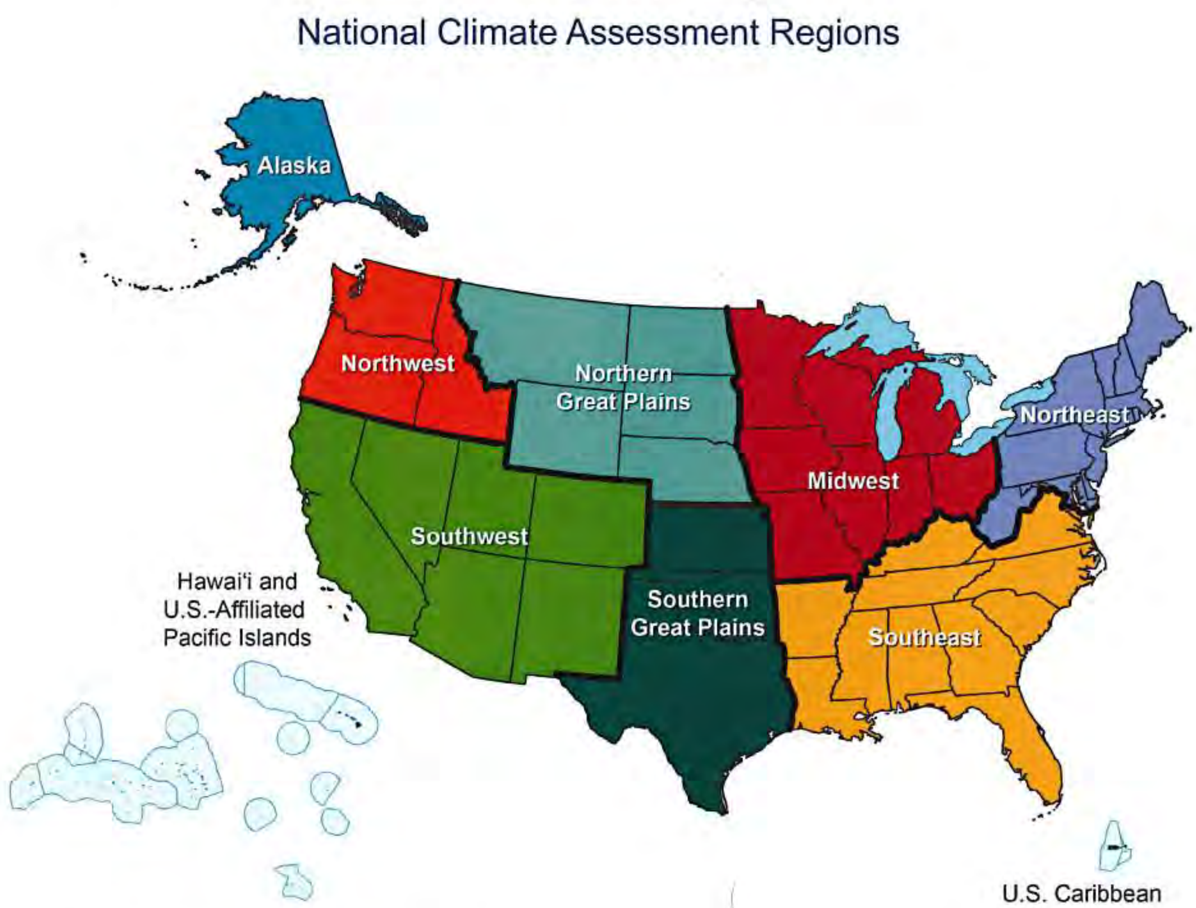

Figure 1: Map of the ten regions used throughout NCA4.

The regions defined in NCA4 are similar to those used in the Third National Climate Assessment (NCA3),[8] with these exceptions: the Great Plains region, formerly stretching from the border of Canada to the border of Mexico, is now divided into the Northern Great Plains and Southern Great Plains along the Nebraska–Kansas border; and content related to the U.S. Caribbean islands is now found in its own chapter, distinct from the Southeast region.

Response Chapters

The response chapters assess the science of adaptation and mitigation, including benefits, tradeoffs, and best practices of ongoing adaptation measures and quantification of economic damages that can be avoided by reducing greenhouse gas emissions. The National Climate Assessment does not evaluate or recommend specific policies.

Economic Estimates

To the extent possible, economic estimates in this report have been converted to 2015 dollars using the U.S. Bureau of Economic Affairs' Implicit Price Deflators for Gross Domestic Product, Table 1.1.9. For more information, please visit: https://bea.gov/national/index.htm. Where documented in the underlying literature, discount rates in specific estimates in this assessment are noted next to those projections.

Use of Scenarios

Climate modeling experts develop climate projections for a range of plausible futures. These projections capture variables such as the relationship between human choices, greenhouse gas (GHG) and particulate matter emissions, GHG concentrations in our atmosphere, and the resulting impacts, including temperature change and sea level rise. Some projections are consistent with continued dependence on fossil fuels, while others are achieved by reducing GHG emissions. The resulting range of projections reflects, in part, the uncertainty that comes with quantifying future human activities and their influence on climate.

The most recent set of climate projections developed by the international scientific community is classified under four Representative Concentration Pathways, or RCPs.[9] A wide range of future socioeconomic assumptions could be consistent with the RCPs used throughout NCA4.

NCA4 focuses on RCP8.5 as a "higher" scenario, associated with more warming, and RCP4.5 as a "lower" scenario with less warming. Other RCP scenarios (e.g., RCP2.6, a "very low" scenario) are used where instructive, such as in analyses of mitigation science issues. To promote understanding while capturing the context of the RCPs, authors use the phrases "a higher scenario (RCP8.5)" and "a lower scenario (RCP4.5)." RCP8.5 is generally associated with higher population growth, less technological innovation, and higher carbon intensity of the global energy mix. RCP4.5 is generally associated with lower population growth, more technological innovation, and lower carbon intensity of the global energy mix. NCA4 does not evaluate the feasibility of the socioeconomic assumptions within the RCPs. Future socioeconomic conditions—and especially the relationship between economic growth, population growth, and innovation—will have a significant impact on which climate change scenario is realized. The use of RCP8.5 and RCP4.5 as core scenarios is broadly consistent with the range used in NCA3.[8] For additional detail on these scenarios and what they represent, please see Appendix 3 (Data Tools and Scenario Products), as well as Chapter 4 of the *Climate Science Special Report*.[10]

Treatment of Uncertainties: Risk Framing, Confidence, and Likelihood

Risk Framing

In March 2016, NASEM convened a workshop, Characterizing Risk in Climate Change Assessments, to assist NCA4 authors in their analyses of climate-related risks across the United States.[11] To help ensure consistency and readability across chapters, USGCRP developed guidance on communicating the risks and opportunities that climate change presents, including the treatment of scientific uncertainties. Where supported by the underlying literature, authors were encouraged to

- describe the full scope of potential climate change impacts, both negative and positive, including more extreme impacts that are less likely but would have severe consequences, and communicate the range of potential impacts and their probabilities of occurrence;

- describe the likelihood of the consequences associated with the range of potential impacts, the character and quality of the consequences, both negative and positive, and the strength of available evidence;

- communicate cascading effects among and within complex systems; and

- quantify risks that could be avoided by taking action.

Additional detail on how risk is defined for this report, as well as how risk-based framing was used, is available in Chapter 1: Overview (see Box 1.2: Evaluating Risks to Inform Decisions).

Traceable Accounts: Confidence and Likelihood

Throughout NCA4's assessment of climate-related risks and impacts, authors evaluated the range of information in the scientific literature to the fullest extent possible, arriving at a series of Key Messages for each chapter. Drawing on guidance developed by the Intergovernmental Panel on Climate Change (IPCC),[12] chapter authors further described the overall reliability in their conclusions using these metrics in their chapter's Traceable Accounts:

- **Confidence** in the validity of a finding based on the type, amount, quality, strength, and consistency of evidence (such as mechanistic understanding, theory, data, models, and expert judgment); the skill, range, and consistency of model projections; and the degree of agreement within the body of literature.

- **Likelihood**, which is based on measures of uncertainty expressed probabilistically (in other words, based on statistical analysis of observations or model results or on the authors' expert judgment).

The author team's expert assessment of confidence for each Key Message is presented in the chapter's Traceable Accounts. Where the authors consider it is scientifically justified to report the likelihood of a particular impact within the range of possible outcomes, Key Messages in the Traceable Accounts also include a likelihood designation. Traceable Accounts describe the process and rationale the authors used in reaching their conclusions, as well as their confidence in these conclusions. They provide additional information about the quality of information used and allow traceability to data and resources.

Confidence Level
Very High
Strong evidence (established theory, multiple sources, confident results, well-documented and accepted methods, etc.), high consensus
High
Moderate evidence (several sources, some consistency, methods vary and/or documentation limited, etc.), medium consensus
Medium
Suggestive evidence (a few sources, limited consistency, models incomplete, methods emerging, etc.), competing schools of thought
Low
Inconclusive evidence (limited sources, extrapolations, inconsistent findings, poor documentation and/or methods not tested, etc.), disagreement or lack of opinions among experts

Likelihood				
Very Likely	Likely	As Likely as Not	Unlikely	Very Unlikely
≥ 9 in 10	≥ 2 in 3	≈ 1 in 2	≤ 1 in 3	≤ 1 in 10

Table 1: This table describes the meaning of the various categories of confidence level and likelihood assessment used in NCA4. The levels of confidence are the same as they appear in the CSSR (NCA4 Volume I). And while the likelihood scale is consistent with the CSSR, there are fewer categories, as that report relies more heavily on quantitative methods and statistics. This "binning" of likelihood is consistent with other USGCRP sustained assessment products, such as the Climate and Health Assessment[4] and NCA3.[8]

Glossary of Terms

NCA4 uses the glossary available on the USGCRP website (http://www.globalchange.gov/climate-change/glossary). It was developed for NCA3 and largely draws from the IPCC glossary of terms. Over time, it has been updated with selected new terms from more recent USGCRP assessments, including *The Impacts of Climate Change on Human Health in the United States* (https://health2016.globalchange.gov/glossary-and-acronyms) and the *Climate Science Special Report* (https://science2017.globalchange.gov/chapter/appendix-e/).

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Northeast

Bartram Bridge in Pennsylvania

Key Message 1

Changing Seasons Affect Rural Ecosystems, Environments, and Economies

The seasonality of the Northeast is central to the region's sense of place and is an important driver of rural economies. Less distinct seasons with milder winter and earlier spring conditions are already altering ecosystems and environments in ways that adversely impact tourism, farming, and forestry. The region's rural industries and livelihoods are at risk from further changes to forests, wildlife, snowpack, and streamflow.

Key Message 2

Changing Coastal and Ocean Habitats, Ecosystems Services, and Livelihoods

The Northeast's coast and ocean support commerce, tourism, and recreation that are important to the region's economy and way of life. Warmer ocean temperatures, sea level rise, and ocean acidification threaten these services. The adaptive capacity of marine ecosystems and coastal communities will influence ecological and socioeconomic outcomes as climate risks increase.

Key Message 3

Maintaining Urban Areas and Communities and Their Interconnectedness

The Northeast's urban centers and their interconnections are regional and national hubs for cultural and economic activity. Major negative impacts on critical infrastructure, urban economies, and nationally significant historic sites are already occurring and will become more common with a changing climate.

Key Message 4

Threats to Human Health

Changing climate threatens the health and well-being of people in the Northeast through more extreme weather, warmer temperatures, degradation of air and water quality, and sea level rise. These environmental changes are expected to lead to health-related impacts and costs, including additional deaths, emergency room visits and hospitalizations, and a lower quality of life. Health impacts are expected to vary by location, age, current health, and other characteristics of individuals and communities.

Key Message 5

Adaptation to Climate Change Is Underway

Communities in the Northeast are proactively planning and implementing actions to reduce risks posed by climate change. Using decision support tools to develop and apply adaptation strategies informs both the value of adopting solutions and the remaining challenges. Experience since the last assessment provides a foundation to advance future adaptation efforts.

Executive Summary

The distinct seasonality of the Northeast's climate supports a diverse natural landscape adapted to the extremes of cold, snowy winters and warm to hot, humid summers. This natural landscape provides the economic and cultural foundation for many rural communities, which are largely supported by a diverse range of agricultural, tourism, and natural resource-dependent industries (see Ch. 10: Ag & Rural, Key Message 4).[1] The recent dominant trend in precipitation throughout the Northeast has been towards increases in rainfall intensity,[2] with increases in intensity exceeding those in other regions of the contiguous United States. Further increases in rainfall intensity are expected,[3] with increases in total precipitation expected during the winter and spring but with little change in the summer.[4] Monthly precipitation in the Northeast is projected to be about 1 inch greater for December through April by end of century (2070–2100) under the higher scenario (RCP8.5).[4]

Ocean and coastal ecosystems are being affected by large changes in a variety of climate-related environmental conditions. These ecosystems support fishing and aquaculture,[5] tourism and recreation, and coastal communities.[6] Observed and projected increases in temperature, acidification, storm frequency and intensity, and sea levels are of particular concern for coastal and ocean ecosystems, as well as local communities and their interconnected social and economic systems. Increasing temperatures and changing seasonality on the Northeast Continental Shelf have affected marine organisms and the ecosystem in various ways. The warming trend experienced in the Northeast Continental Shelf has been associated with many fish and invertebrate species moving northward and to greater depths.[7,8,9,10,11] Because of the diversity of the Northeast's coastal landscape, the impacts

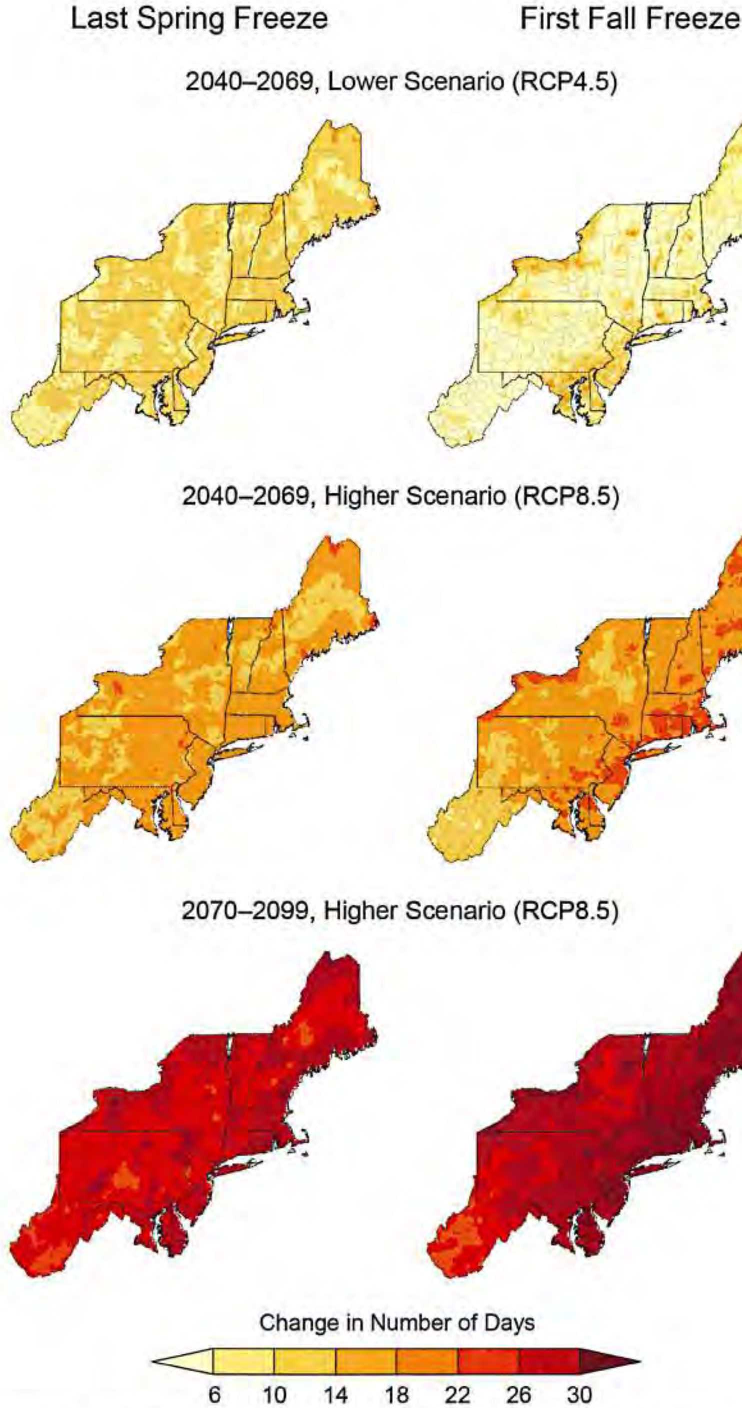
from storms and sea level rise will vary at different locations along the coast.[12,13]

Northeastern cities, with their abundance of concrete and asphalt and relative lack of vegetation, tend to have higher temperatures than surrounding regions due to the urban heat island effect. During extreme heat events, nighttime temperatures in the region's big cities are generally several degrees higher than surrounding regions, leading to higher risk of heat-related death. Urban areas are at risk for large numbers of evacuated and displaced populations and damaged infrastructure due to both extreme precipitation events and recurrent flooding, potentially requiring significant emergency response efforts and consideration of a long-term commitment to rebuilding and adaptation, and/or support for relocation where needed. Much of the infrastructure in the Northeast, including drainage and sewer systems, flood and storm protection assets, transportation systems, and power supply, is nearing the end of its planned life expectancy. Climate-related disruptions will only exacerbate existing issues with aging infrastructure. Sea level rise has amplified storm impacts in the Northeast (Key Message 2), contributing to higher surges that extend farther inland, as demonstrated in New York City in the aftermath of Superstorm Sandy in 2012.[14,15,16] Service and resource supply infrastructure in the Northeast is at increasing risk of disruption, resulting in lower quality of life, economic declines, and increased social inequality.[17] Loss of public services affects the capacity of communities to function as administrative and economic centers and triggers disruptions of interconnected supply chains (Ch. 16: International, Key Message 1).

Increases in annual average temperatures across the Northeast range from less than 1°F (0.6°C) in West Virginia to about 3°F (1.7°C) or more in New England since 1901.[18,19] Although the relative risk of death on very hot days is lower today than it was a few decades ago, heat-related illness and death remain significant public health problems in the Northeast.[20,21,22,23] For example, a study in New York City estimated that in 2013 there were 133 excess deaths due to extreme heat.[24] These projected increases in temperature are expected to lead to substantially more premature deaths, hospital admissions, and emergency department visits across the Northeast.[23,25,26,27,28,29] For example, in the Northeast we can expect approximately 650 additional premature deaths per year from extreme heat by the year 2050 under either a lower (RCP4.5) or higher (RCP8.5) scenario and from 960 (under RCP4.5) to 2,300 (under RCP8.5) more premature deaths per year by 2090.[29]

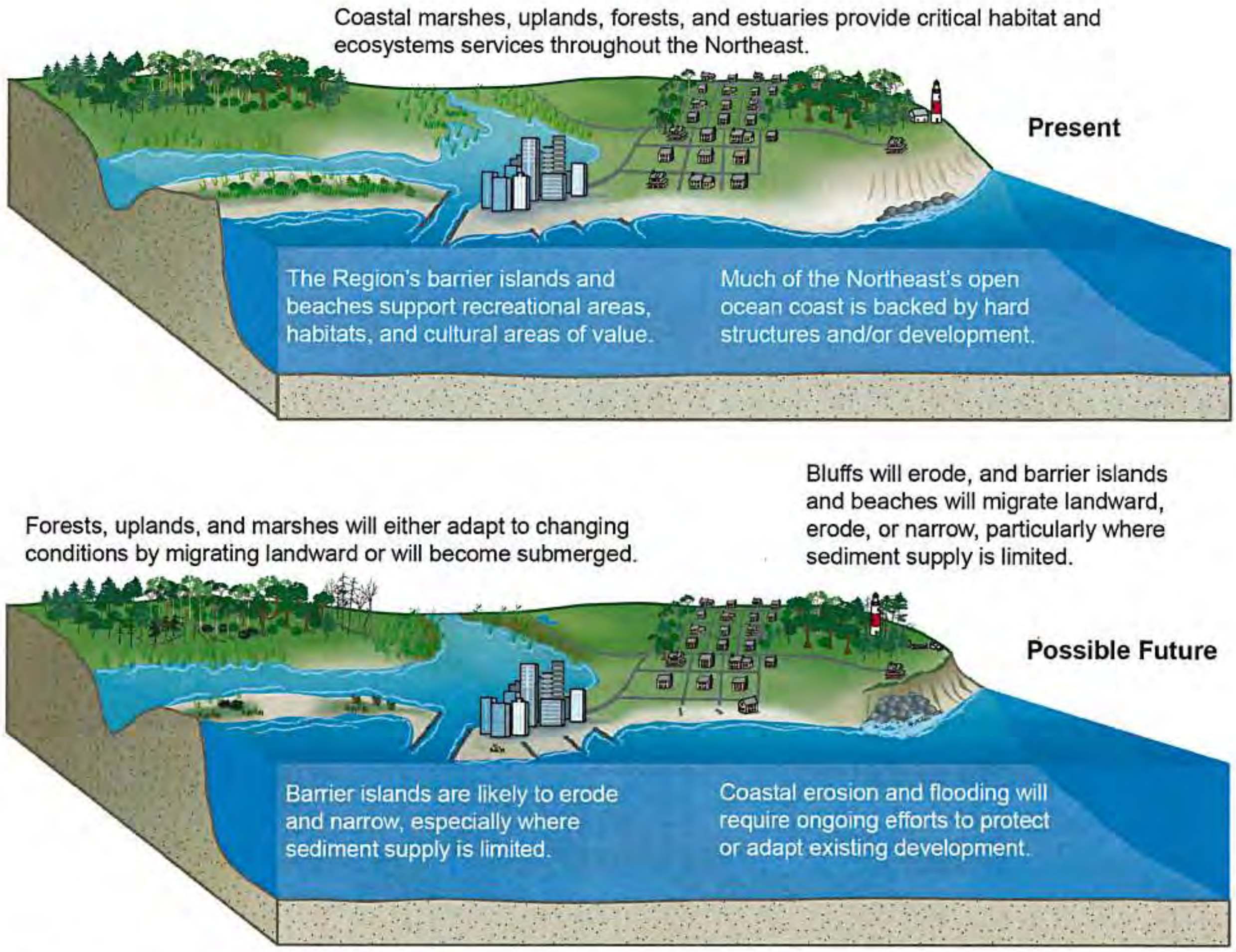
Communities, towns, cities, counties, states, and tribes across the Northeast are engaged in efforts to build resilience to environmental challenges and adapt to a changing climate. Developing and implementing climate adaptation strategies in daily practice often occur in collaboration with state and federal agencies (e.g., New Jersey Climate Adaptation Alliance 2017, New York Climate Clearinghouse 2017, Rhode Island STORMTOOLS 2017, EPA 2017, CDC 2015[30,31,32,33,34]). Advances in rural towns, cities, and suburban areas include low-cost adjustments of existing building codes and standards. In coastal areas, partnerships among local communities and federal and state agencies leverage federal adaptation tools and decision support frameworks (for example, NOAA's Digital Coast, USGS's Coastal Change Hazards Portal, and New Jersey's Getting to Resilience). Increasingly, cities and towns across the Northeast are developing or implementing plans for adaptation and resilience in the face of changing climate (e.g., EPA 2017[33]). The approaches are designed to maintain and enhance the everyday lives of residents and promote economic development. In some cities, adaptation planning has been used to respond to present and future challenges in the built environment. Regional efforts have recommended changes in design standards when building, replacing, or retrofitting infrastructure to account for a changing climate.

Lengthening of the Freeze-Free Period



These maps show projected shifts in the date of the last spring freeze (left column) and the date of the first fall freeze (right column) for the middle of the century (as compared to 1979–2008) under the lower scenario (RCP4.5; top row) and the higher scenario (RCP8.5; middle row). The bottom row shows the shift in these dates for the end of the century under the higher scenario. By the middle of the century, the freeze-free period across much of the Northeast is expected to lengthen by as much as two weeks under the lower scenario and by two to three weeks under the higher scenario. By the end of the century, the freeze-free period is expected to increase by at least three weeks over most of the region. *From Figure 18.3 (Source: adapted from Wolfe et al. 2018[35]).*

Coastal Impacts of Climate Change



(top) The northeastern coastal landscape is composed of uplands and forested areas, wetlands and estuarine systems, mainland and barrier beaches, bluffs, headlands, and rocky shores, as well as developed areas, all of which provide a variety of important services to people and species. (bottom) Future impacts from intense storm activity and sea level rise will vary across the landscape, requiring a variety of adaptation strategies if people, habitats, traditions, and livelihoods are to be protected. *From Figure 18.7 (Source: U.S. Geological Survey).*

A number of coastal communities in the Northeast region have strong social and cultural ties to marine fisheries, and in some communities, fisheries represent an important economic activity as well.[196,197] Future ocean warming and acidification, which are expected under all scenarios considered, would affect fish stocks and fishing opportunities available to coastal communities. Fisheries targeting species at the southern extent of their range have already experienced substantial declines in landings with rising ocean temperatures,[170,173,198,199,200] and this pattern is projected to continue in the future (e.g., Cooley et al. 2015, Pershing et al. 2015, Le Bris et al. 2018[39,40,191]). Fishers may need to travel farther to fishing locations for species they currently catch,[189] increasing fuel and crew costs. Distribution shifts (Figure 18.6) can also create opportunities to target new species moving into an area.[155] The impacts and opportunities associated with these changes will not be evenly shared within or among fisheries, fleets, or communities; as such, adaptation may alter social dynamics, cultural ties, and economic benefits.[201,202,203]

Sea Level Rise, Storms, and Flooding

Along the Mid-Atlantic coast (from Cape Hatteras, North Carolina, to Cape Cod, Massachusetts), several decades of tide gauge data through 2009 have shown that sea level rise rates were three to four times higher than the global average rate.[46,205,206] The region's sea level rise rates are increased by land subsidence (sinking)—largely due to vertical land movement related to the melting of glaciers from the last ice age—which leaves much of the land in this region sinking with respect to current sea level.[47,207,208,209] Additionally, shorter-term fluctuations in the variability of ocean dynamics,[210,211] atmospheric shifts,[212,213] and ice mass loss from Greenland and Antarctica[214] have been connected to these recent accelerations in the sea level rise rate in the region. For example, a slowdown of the Gulf Stream during a shorter period of extreme sea level rise observed over 2009–2010 has been linked to a weakening of the Atlantic meridional overturning circulation—the northward flow of upper-level warm, salty waters in the Atlantic (including the Gulf Stream current) and the southward flow of colder, deeper waters.[215] These higher-than-average rates of sea level rise measured in the Northeast have also led to a 100%–200% increase in high tide flooding in some places, causing more persistent and frequent (so-called nuisance flooding) impacts over the last few decades.[44,47,216,217]

Coastal flood risks from storm-driven precipitation and surges are major drivers of coastal change[218,219] and are also amplified by sea level increases.[217,220,221] Storms have unique climatological features in the Northeast—Nor'easters (named for the low-pressure systems typically impacting New England and the Mid-Atlantic with strong northeasterly winds blowing from the ocean over coastal areas) typically occur between September and April, and when coupled with the Atlantic hurricane season between June and September, the region is susceptible to major storms nearly year-round. Storm flood heights driven by hurricanes in New York City increased by more than 3.9 feet (1.2 m) over the last thousand years.[14] When coupled with storm surges, sea level rise can pose severe risks of flooding, with consequent physical and mental health impacts on coastal populations (see Key Messages 4 and 5).

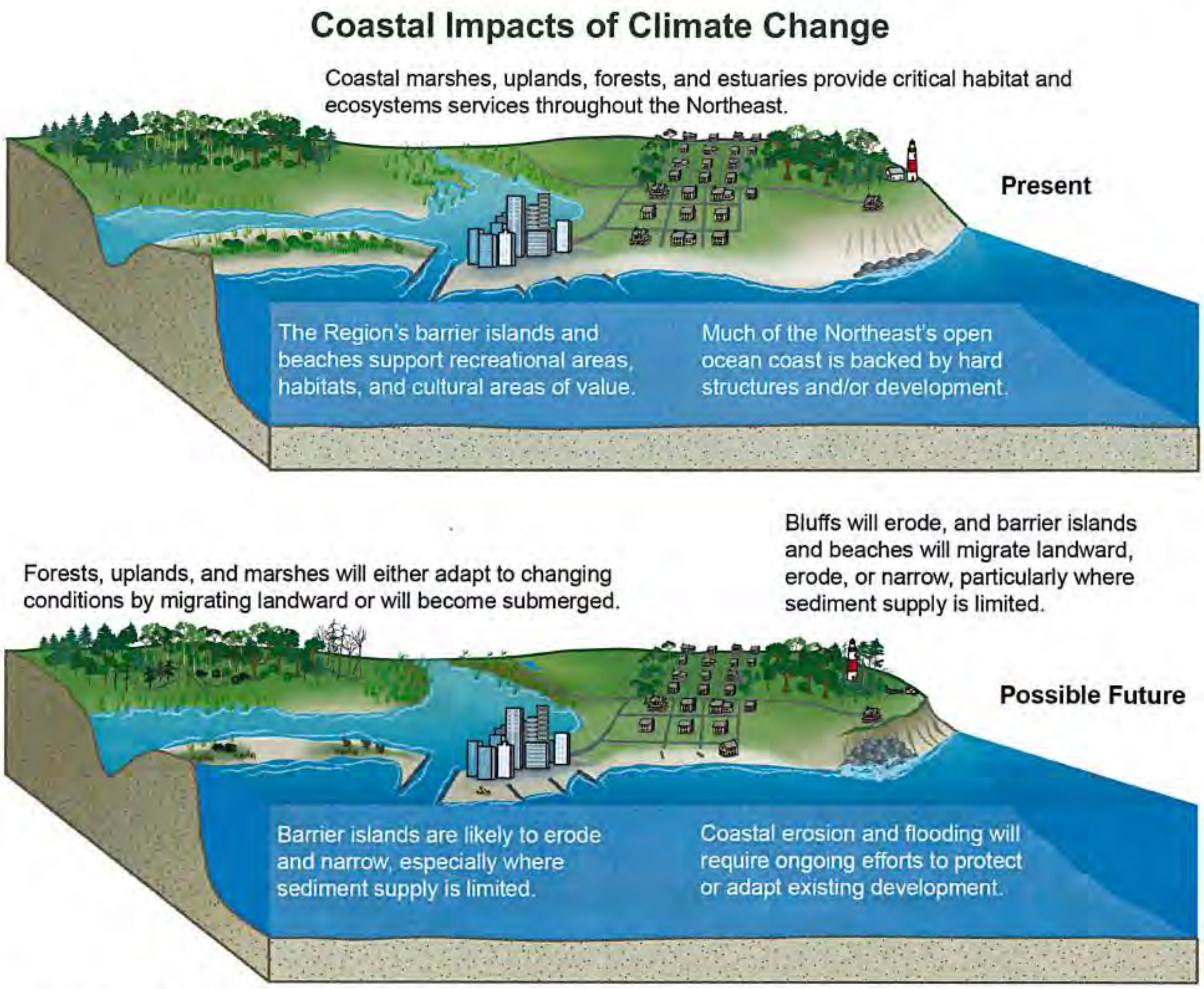


Figure 18.7: (top) The northeastern coastal landscape is composed of uplands and forested areas, wetlands and estuarine systems, mainland and barrier beaches, bluffs, headlands, and rocky shores, as well as developed areas, all of which provide a variety of important services to people and species. (bottom) Future impacts from intense storm activity and sea level rise will vary across the landscape, requiring a variety of adaptation strategies if people, habitats, traditions, and livelihoods are to be protected. Source: U.S. Geological Survey.

Landscape Change and Impacts on Ecosystems Services

Because of the diversity of the Northeast's coastal landscape, the impacts from storms and sea level rise will vary at different locations along the coast (Figure 18.7).[12,13] Rocky and heavily developed coasts have limited infiltration capacity to absorb these impacts, and thus, these low-elevation areas will become gradually inundated.[222,223] However, more dynamic environments, such as mainland and barrier beaches, bluffs, and coastal wetlands, have evolved over thousands of years in response to physical drivers. Such responses include erosion, overwashing, vertical accretion (increasing elevation due to sediment movement), flooding in response to storm events,[218,224,225] and landward migration over the longer term as sea level has risen.[226] Uplands, forests, and agricultural lands can provide transitional areas for these more dynamic settings, wherein the land gradually converts to a tidal marsh.

Varied ecosystem services and natural features have long attracted and sustained people along the coast of the Northeast region. Ecosystem services—including the provisioning of

BUSINESS NEWS MARCH 22, 2019 / 6:28 PM / 5 MONTHS AGO

Canada's SNC Lavalin eyes ways to protect business amid political crisis

Allison Lampert 4 MIN READ

MONTREAL (Reuters) - SNC Lavalin Group's chief executive said on Friday the company is looking at ways to protect its business in the event it loses a corruption trial that has created a political crisis for Canadian Prime Minister Justin Trudeau.

FILE PHOTO: Neil Bruce, president and CEO of SNC-Lavalin, poses in their head offices in Montreal, November 10, 2015.
REUTERS/Christinne Muschi

An SNC-Lavalin board subcommittee is weighing the construction and engineering company's options as it takes "steps to minimize the effect of any potential sort of bad outcome in a few years' time," chief executive Neil Bruce told Reuters in an interview.

Trudeau has been on the defensive since Feb. 7 over allegations that top officials working for him leaned on former Justice Minister Jody Wilson-Raybould last year to ensure that the construction company avoided a corruption trial. Trudeau has denied the allegations.

At the affair's center is a request by SNC-Lavalin for a remediation agreement that would have enabled it to avoid a court case which, if lost, would block it from federal government contracts for a decade. SNC-Lavalin is facing fraud and corruption charges related to allegations that former executives paid bribes to win contracts in Libya under Muammar Gaddafi's regime, which fell in 2011.

Bruce said SNC is now focused on defending itself in court, with little expectation that a remediation would become available. Any court decision which would likely be years away.

“We don’t want to be reacting too late or not early enough if the worst came to the worst,” he said. “We’ve got to be prudent and make sure that we position the company.”

Being blocked from federal contracts would raise the threat of job cuts among the company’s Canadian workforce of 9,000.

“If we were in a position where for whatever reason we couldn’t do work with a certain customer or in a certain country then we would plan all of that and make sure that our business development efforts and the work we were chasing and hopefully winning didn’t fall into that category. That’s part of the mitigation plan.”

Trudeau has often referred to the 9,000 potential job losses as a reason for helping the company, but Bruce told the CBC earlier this week that he never gave a specific number.

SNC wanted to take advantage of new legislation to pay a large fine rather than be prosecuted.

Bruce said the political issue engulfing the Liberals has “very little to do” with the Montreal-based company whose backlog of about C$15 billion ($11.17 billion) is expected to rise during the first quarter.

But politics impacted SNC’s ability to win new work in Saudi Arabia in December and January, amid tense relations between Riyadh and Ottawa. Saudi Arabia froze new trade with Ottawa in August after Canada demanded the release of jailed rights activists.

"Generally we would expect to win sometimes one in two, sometimes one in three," he said. "And that actually went down to zero in a couple of areas."

While the dispute has not impacted current contracts underway in Saudi Arabia, Bruce said SNC's backlog in the country would taper off toward the end of the year if it didn't win any new contracts in 2019.

The CEO also said an accelerated arbitration process around a delayed Chile project, which hit results from its mining unit in the fourth quarter, would likely not be resolved in 2019.

Reporting by Allison Lampert in Montreal; Editing by Amran Abocar, Sandra Maler and James Dalgleish

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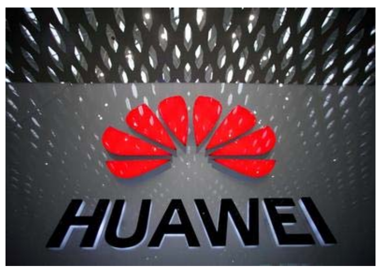

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SNC has 'seriously' and 'repeatedly' breached aspects of its contracts, says Codelco

The Chuquicamata copper mine in northern Chile. *AP Photo/Jorge Saenz*

Bloomberg News
Sandrine Rastello and Laura Millan Lombrana

March 26, 2019
7:56 AM EDT

Filed under
Commodities › **Mining**

SNC-Lavalin Group Inc., the embattled engineering firm at the heart of Canada's biggest political crisis in years, has been dealt another blow in Chile.

Copper producer Codelco said Monday that it canceled a contract worth US$260 million to build two new acid plants in the Chuquicamata mine. Montreal-based SNC has "seriously" and "repeatedly" breached aspects of its

contracts, according to Codelco, which cited delays in construction and in payments to subcontractors, as well as quality issues.

"Codelco made several attempts to resolve the problems facing the project, with the last attempt in February," according to the statement from the Santiago-based company.

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SNC-Lavalin said in a statement that is "appalled" and "surprised" by the decision that puts the project's completion and commissioning date further at risk. The company is demobilizing the job site and assessing the legal and financial impact of Codelco's decision. It is also preparing dispute resolution actions to recover as much as possible of the previously announced losses that are due directly to the client and to poor sub-contractor performance.

Difficulties around the contract were initially flagged by SNC on Jan. 28, when it disclosed trouble at an unidentified mine in Latin America and took a writedown on its energy unit amid a diplomatic spat between Canada and Saudi Arabia. About two weeks later, it said it had failed to reach an agreement with the miner and that the parties would try to settle the dispute with an accelerated arbitration process. SNC cut its profit outlook for a second time and said the impasse would contribute up to a $350 million negative drag on the mining and metallurgy unit's fourth-quarter earnings before interest and taxes.

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TRUDEAU IMPACT

SNC has been at the centre of a controversy that has engulfed Justin Trudeau after his former attorney-general said the Canadian prime minister and some of his aides pressured her to intervene to help the construction firm avoid a trial.

SNC has been charged with paying bribes related to work in Libya more than a decade ago. Trudeau has said he supported a so-called deferred prosecution agreement for SNC because the company employs 9,000 people in Canada. The company has since indicated it was giving up on settling the

SNC’s stock has declined 29 per cent since Jan. 25, the last trading day before the company disclosed a “serious problem” with a mining contract. The shares fell 0.6 per cent to $34.35 in Toronto Monday.

SMELTER EXPANSION

Codelco, the world’s largest producer of copper, is investing US$2.15 billion to upgrade its four smelters to comply with new regulations that require them to capture 95 per cent of emissions.

Work at the smelters in the Chuquicamata and Salvador mines weren’t completed by Dec. 13, when the new rules kicked in, forcing Codelco to halt them. Operations were initially expected to resume at the end of January at Salvador and at the end of February at Chuquicamata.

Codelco on Monday said it now expects to partly resume operations at Chuquicamata during the second half of April. The smelter could be fully operational 15 to 20 days later, the company said.

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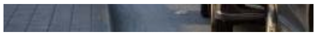

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GAO

Report to Congressional Requesters

November 2009

NUCLEAR WASTE MANAGEMENT

Key Attributes, Challenges, and Costs for the Yucca Mountain Repository and Two Potential Alternatives

GAO-10-48

GAO
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Highlights

Highlights of GAO-10-48, a report to congressional requesters

NUCLEAR WASTE MANAGEMENT

Key Attributes, Challenges, and Costs of the Yucca Mountain Repository and Two Potential Alternatives

Why GAO Did This Study

High-level nuclear waste—one of the nation's most hazardous substances—is accumulating at 80 sites in 35 states. The United States has generated 70,000 metric tons of nuclear waste and is expected to generate 153,000 metric tons by 2055. The Nuclear Waste Policy Act of 1982, as amended, requires the Department of Energy (DOE) to dispose of the waste in a geologic repository at Yucca Mountain, about 100 miles northwest of Las Vegas, Nevada. However, the repository is more than a decade behind schedule, and the nuclear waste generally remains at the commercial nuclear reactor sites and DOE sites where it was generated.

This report examines the key attributes, challenges, and costs of the Yucca Mountain repository and the two principal alternatives to a repository that nuclear waste management experts identified: storing the nuclear waste at two centralized locations and continuing to store the waste on site where it was generated. GAO developed models of total cost ranges for each alternative using component cost estimates provided by the nuclear waste management experts. However, GAO did not compare these alternatives because of significant differences in their inherent characteristics that could not be quantified.

What GAO Recommends

GAO is making no recommendations in this report. In written comments, DOE and NRC generally agreed with the report.

View GAO-10-48 or key components.
For more information, contact Mark Gaffigan at 202-512-3841 or gaffiganm@gao.gov.

What GAO Found

The Yucca Mountain repository is designed to provide a permanent solution for managing nuclear waste, minimize the uncertainty of future waste safety, and enable DOE to begin fulfilling its legal obligation under the Nuclear Waste Policy Act to take custody of commercial waste, which began in 1998. However, project delays have led to utility lawsuits that DOE estimates are costing taxpayers about $12.3 billion in damages through 2020 and could cost $500 million per year after 2020, though the outcome of pending litigation may affect the government's total liability. Also, the administration has announced plans to terminate Yucca Mountain and seek alternatives. Even if DOE continues the program, it must obtain a Nuclear Regulatory Commission construction and operations license, a process likely to be delayed by budget shortfalls. GAO's analysis of DOE's cost projections found that a repository to dispose of 153,000 metric tons would cost from $41 billion to $67 billion (in 2009 present value) over a 143-year period until the repository is closed. Nuclear power rate payers would pay about 80 percent of these costs, and taxpayers would pay about 20 percent.

Centralized storage at two locations provides an alternative that could be implemented within 10 to 30 years, allowing more time to consider final disposal options, nuclear waste to be removed from decommissioned reactor sites, and the government to take custody of commercial nuclear waste, saving billions of dollars in liabilities. However, DOE's statutory authority to provide centralized storage is uncertain, and finding a state willing to host a facility could be extremely challenging. In addition, centralized storage does not provide for final waste disposal, so much of the waste would be transported twice to reach its final destination. Using cost data from experts, GAO estimated the 2009 present value cost of centralized storage of 153,000 metric tons at the end of 100 years to range from $15 billion to $29 billion but increasing to between $23 billion and $81 billion with final geologic disposal.

On-site storage would provide an alternative requiring little change from the status quo, but would face increasing challenges over time. It would also allow time for consideration of final disposal options. The additional time in on-site storage would make the waste safer to handle, reducing risks when waste is transported for final disposal. However, the government is unlikely to take custody of the waste, especially at operating nuclear reactor sites, which could result in significant financial liabilities that would increase over time. Not taking custody could also intensify public opposition to spent fuel storage site renewals and reactor license extensions, particularly with no plan in place for final waste disposition. In addition, extended on-site storage could introduce possible risks to the safety and security of the waste as the storage systems degrade and the waste decays, potentially requiring new maintenance and security measures. Using cost data from experts, GAO estimated the 2009 present value cost of on-site storage of 153,000 metric tons at the end of 100 years to range from $13 billion to $34 billion but increasing to between $20 billion to $97 billion with final geologic disposal.

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Abbreviations

DOE	Department of Energy
EPA	Environmental Protection Agency
NRC	Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act of 1982

United States Government Accountability Office
Washington, DC 20548

November 4, 2009

The Honorable Barbara Boxer
Chairman
Committee on Environment and Public Works
United States Senate

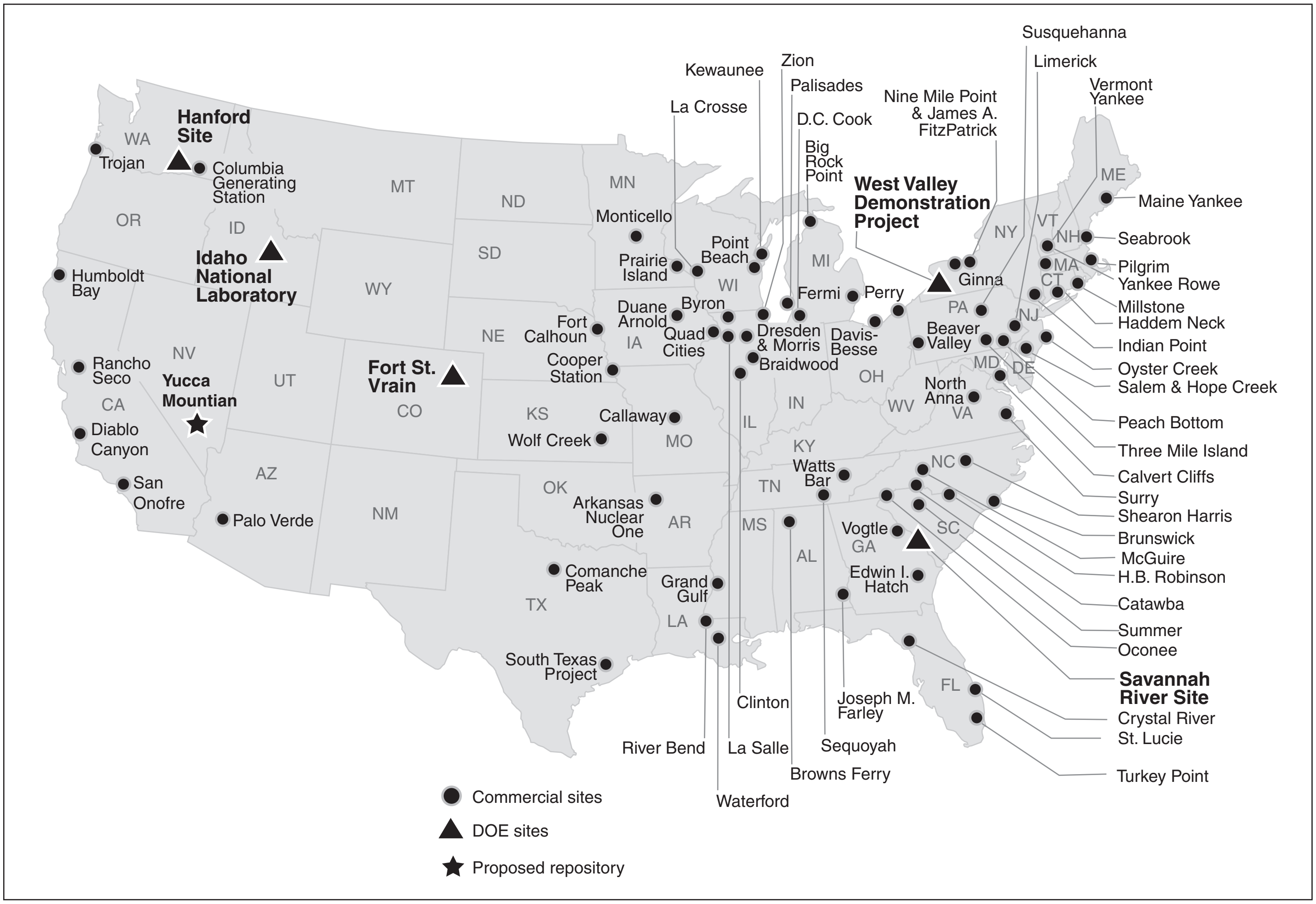
The Honorable Harry Reid
United States Senate

The Honorable John Ensign
United States Senate

High-level nuclear waste consists mostly of spent nuclear fuel removed from commercial power reactors and is considered one of the most hazardous substances on earth. The U.S. national inventory of 70,000 metric tons of nuclear waste—enough to fill a football field more than 15 feet deep—has been accumulating at 80 sites in 35 states since the mid-1940s and is expected to more than double to 153,000 metric tons by 2055. The current national policy of constructing a federal repository to dispose of this waste at Yucca Mountain—which is about 100 miles northwest of Las Vegas, Nevada—has already been delayed more than a decade. As a result, nuclear waste generally remains at the sites where it was generated. Experts and regulators believe the nuclear waste, if properly stored and monitored, can be kept safe and secure on-site for decades; but communities across the country have raised concerns about the waste's lethal nature and the possibility of natural disasters or terrorism, particularly at sites near urban centers or sources of drinking water. Industry has also raised concerns that local communities will not support the expansion of the nuclear energy industry without a final waste disposition pathway. Many experts and communities view nuclear energy as a potential means of meeting future energy demands while reducing reliance on fossil fuels and cutting carbon emissions, a key contributor to climate change.

In addition to the spent nuclear fuel generated by commercial power reactors, the Department of Energy (DOE) owns and manages about 19 percent of the nuclear waste—referred to as DOE-managed spent nuclear fuel and high-level waste—which consists of spent nuclear fuel from power, research, and navy shipboard reactors, and high-level nuclear waste from the nation's nuclear weapons program. (See fig. 1 for the locations where nuclear waste is stored.)

Figure 1: Current Storage Sites and Proposed Repository for High-Level Nuclear Waste



Source: DOE.

Note: Locations are approximate. DOE has reported that it is responsible for managing nuclear waste at 121 sites in 39 states, but DOE officials told us that several sites have only research reactors that generate small amounts of waste that will be consolidated at the Idaho National Laboratory for packaging prior to disposal.

Under the Nuclear Waste Policy Act of 1982 (NWPA), as amended, DOE was to evaluate one or more national geologic repositories that would be designated to permanently store commercial spent nuclear fuel and DOE-managed spent nuclear fuel and high-level waste. NWPA was amended in 1987 to direct DOE to evaluate only the Yucca Mountain site. In 2002, the president recommended and the Congress approved the Yucca Mountain site as the nation's geologic repository. The repository is intended to

isolate nuclear waste from humans and the environment for thousands of years, long enough for its radioactivity to decay to near natural background levels. NWPA set January 31, 1998, as the date for DOE to start accepting nuclear waste for disposal. To meet this goal, DOE has spent more than $14 billion for design, engineering, and testing activities.[1] In June 2008, DOE submitted a license application to the Nuclear Regulatory Commission (NRC) for approval to construct the repository. In July 2008, DOE reported that its best achievable date for opening the repository, if it receives NRC approval, is in 2020. Delays in the Yucca Mountain repository have resulted in a need for continued storage of the waste onsite, leaving industry uncertain regarding the licensing of new nuclear power reactors and the nation uncertain regarding a final disposition of the waste.

In March 2009, the Secretary of Energy testified that the administration planned to terminate the Yucca Mountain repository. Since then, the administration has announced plans to study alternatives to geologic disposal at Yucca Mountain before making a decision on a future nuclear waste management strategy, which the administration said could include reprocessing or other complementary strategies.

In this context, you asked us to identify key aspects of DOE's nuclear waste management program and other possible management approaches. Specifically, you asked us to examine (1) the key attributes, challenges, and costs of the Yucca Mountain repository; (2) and identify alternative nuclear waste management approaches; (3) the key attributes, challenges, and costs of storing the nuclear waste at two centralized sites; and (4) the key attributes, challenges, and costs of continuing to store the nuclear waste at its current locations. The centralized storage and onsite storage options—both with disposal scenarios—were the two most likely alternative approaches identified by the experts we interviewed. We are also providing information on what is known about sources of funding—primarily taxpayers and nuclear power rate payers—for the Yucca Mountain repository and the two alternative approaches.

To examine the key attributes, challenges, and costs of the Yucca Mountain repository, we obtained reports and supporting documentation

[1]In constant fiscal year 2009 dollars. Funding comes primarily from fees collected from electric power companies operating commercial reactors and appropriations for DOE-managed spent nuclear fuel and high-level waste.

from DOE, NRC, the National Academy of Sciences, and the Nuclear Waste Technical Review Board. Specifically, we used DOE's report on the Yucca Mountain repository's total lifecycle cost to analyze the cost for disposing of either (1) 70,000 metric tons of nuclear waste, which is the statutory cap on the amount of waste that can be disposed of at Yucca Mountain, or (2) 153,000 metric tons, which is the estimated total amount of nuclear waste that has already been generated and will be generated if all currently operating commercial reactors operate for a 60-year lifespan.[2] We then discounted these costs to 2009 present value.

To identify alternative nuclear waste management approaches, we interviewed DOE officials, experts at the National Academy of Sciences and the Nuclear Waste Technical Review Board, and executives at the Nuclear Energy Institute, among others. Based on their comments, we identified two generic alternative approaches for managing this waste for at least a 100-year period before it is disposed in a repository: storing the nuclear waste at two centralized facilities—referred to as centralized storage—and continuing to store the nuclear waste on site at their current facilities—referred to as on-site storage. To examine the key attributes, challenges, and costs of each alternative, we asked nuclear waste management experts from federal agencies, industry, academic institutions, and concerned groups to comment on the attributes and challenges of each alternative, provide relevant cost data, and comment on the assumptions and cost components that we used to develop cost models for the alternatives. We then used the models to produce the total cost ranges for each alternative with and without final disposal in a geologic repository at the end of a 100-year specific time period. In addition, we analyzed onsite storage for longer periods than 100 years. We analyzed costs associated with storing 70,000 metric tons and 153,000 metric tons and discounted the costs to 2009 present value.

We did not compare the Yucca Mountain cost range to the ranges of other alternatives because of significant differences in inherent characteristics of these alternatives that our modeling work could not quantify. For example, the safety, health, and environmental risks for each are very different, which needs to be considered in the policy debate on nuclear waste management decisions. (See app. I for additional information about our scope and methodology, app. II for our methodology for soliciting

[2]DOE, *Analysis of the Total System Lifecycle Cost of the Civilian Radioactive Waste Management Program, Fiscal Year 2007*, DOE/RW-0591 (Washington, D.C., July 2008).

comments from nuclear waste management experts, and app. III for a list of these experts.)

We conducted this performance audit from April 2008 to October 2009 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

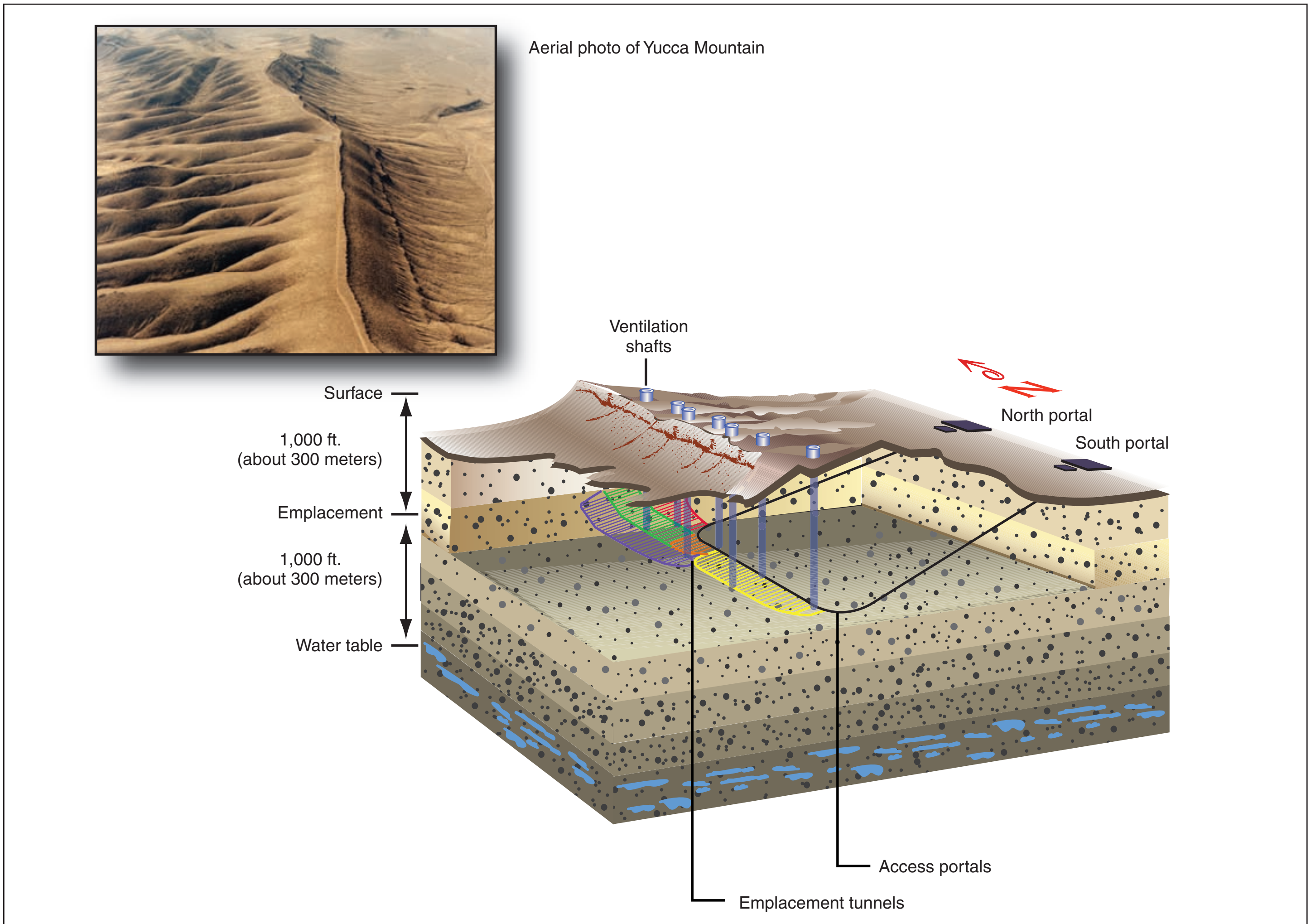
Nuclear waste is long-lived and very hazardous—without protective shielding, the intense radioactivity of the waste can kill a person within minutes or cause cancer months or even decades after exposure.[3] Thus, careful management is required to isolate it from humans and the environment. To accomplish this, the National Academy of Sciences first endorsed the concept of nuclear waste disposal in deep geologic formations in a 1957 report to the U.S. Atomic Energy Commission, which has since been articulated by experts as the safest and most secure method of permanent disposal.[4] However, progress toward developing a geologic repository was slow until NWPA was enacted in 1983. Citing the potential risks of the accumulating amounts of nuclear waste, NWPA required the federal government to take responsibility for the disposition of nuclear waste and required DOE to develop a permanent geologic repository to protect public health and safety and the environment for

[3]For the purposes of our report, nuclear waste includes both spent nuclear fuel—fuel that has been withdrawn from a nuclear reactor following irradiation—and high-level radioactive waste—generally the material resulting from the reprocessing of spent nuclear fuel. Nuclear waste—specifically spent nuclear fuel—is also very thermally hot. As the radioactive elements in spent nuclear fuel decay, they give off heat. However, according to DOE data, a spent nuclear fuel assembly can lose nearly 80 percent of its heat 5 years after it has been removed from a reactor and about 95 percent of its heat after 100 years.

[4]National Academy of Sciences, *The Disposal of Radioactive Waste on Land*, (Washington, D.C., September 1957). This report suggested several potential alternatives for disposal of nuclear waste, stressing that although there are many potential sites for geologic disposal of waste at various depths and in various geologic formations, further research was needed regarding specific waste forms and specific geologic formations, including disposal in deep underground formations. The report stated, "the hazard related to radioactive waste is so great that no element of doubt should be allowed to exist regarding safety." Subsequent reports by the National Academy of Sciences and others have continued to endorse geologic isolation of nuclear waste and have suggested that engineered barriers, such as corrosion-resistant containers, can provide additional layers of isolation.

current and future generations. Specifically, the act required DOE to study several locations around the country for possible repository sites and develop a contractual relationship with industry for disposal of the nuclear waste. The Congress amended NWPA in 1987 to restrict scientific study and characterization of a possible repository to only Yucca Mountain. (Fig. 2 shows the north crest of Yucca Mountain and a cut-out of the proposed mined repository.)

Figure 2: Aerial View and Cut-Out of the Yucca Mountain Repository



Source: DOE.

After the Congress approved Yucca Mountain as a suitable site for the development of a permanent nuclear waste repository in 2002, DOE began

preparing a license application for submittal to NRC, which has regulatory authority over commercial nuclear waste management facilities. DOE submitted its license application to NRC in June 2008, and NRC accepted the license application for review in September 2008. NWPA requires NRC to complete its review of DOE's license application for the Yucca Mountain repository in 3 years, although a fourth year is allowed if NRC deems it necessary and complies with certain reporting requirements.

To pay the nuclear power industry's share of the cost for the Yucca Mountain repository, NWPA established the Nuclear Waste Fund, which is funded by a fee of one mill (one-tenth of a cent) per kilowatt-hour of nuclear-generated electricity that the federal government collects from electric power companies. DOE reported that, at the end of fiscal year 2008, the Nuclear Waste Fund contained $22 billion, with an additional $1.9 billion projected to be added in 2009. DOE receives money from the Nuclear Waste Fund through congressional appropriations. Additional funding for the repository comes from an appropriation which provides for the disposal cost of DOE-managed spent nuclear fuel and high-level waste.

NWPA caps nuclear waste that can be disposed of at the Yucca Mountain repository at 70,000 metric tons until a second repository is available. However, the nation has already accumulated about 70,000 metric tons of nuclear waste at current reactor sites and DOE facilities. Without a change in the law to raise the cap or to allow the construction of a second repository, DOE can dispose of only the current nuclear waste inventory. The nation will have to develop a strategy for an additional 83,000 metric tons of waste expected to be generated if NRC issues 20-year license extensions to all of the currently operating nuclear reactors.[5] This amount does not include any nuclear waste generated by new reactors or future defense activities, or greater than class C nuclear waste.[6] According to

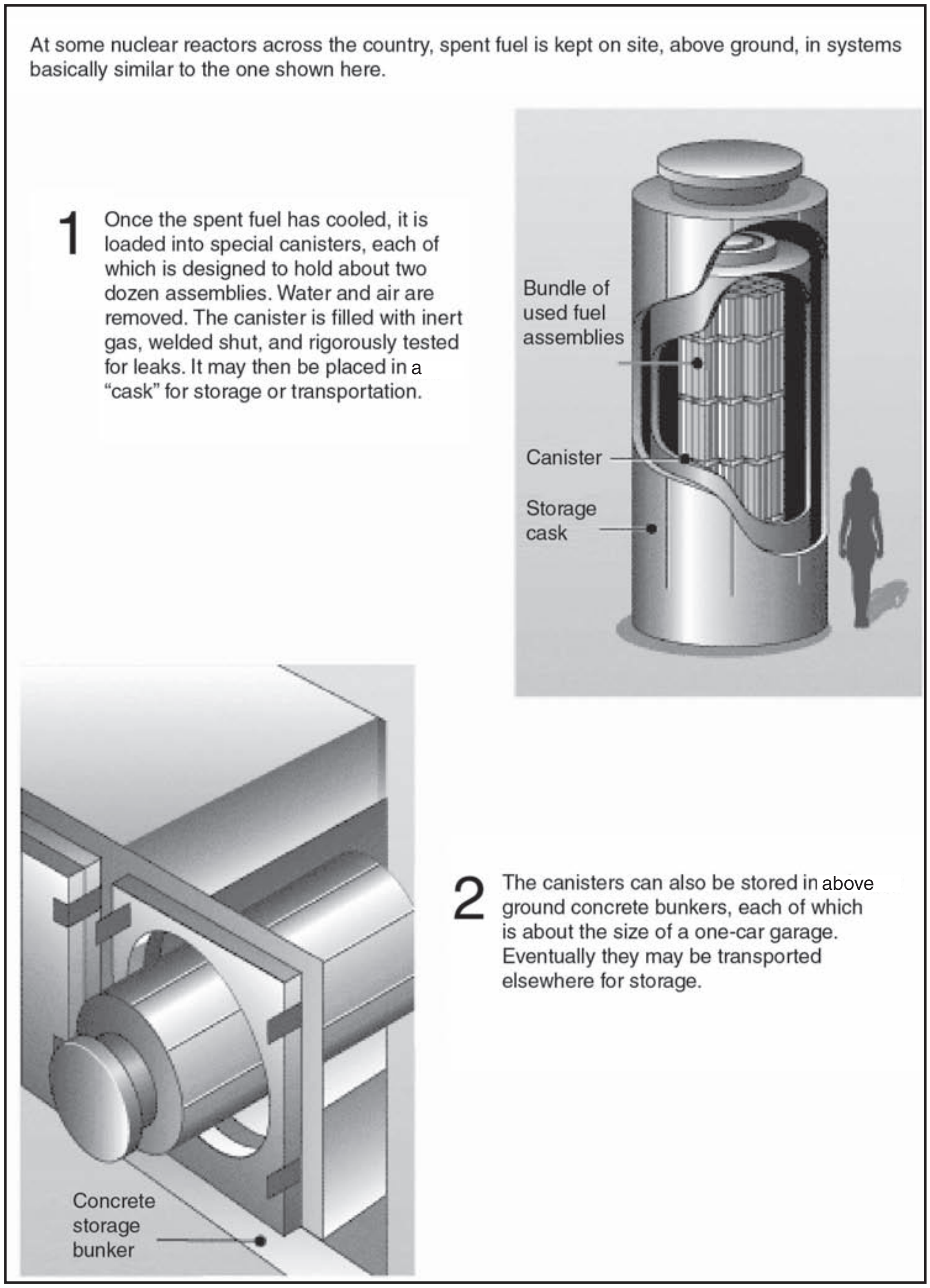
[5]NRC has already issued license extensions for 54 reactors, enabling them to operate for a total of 60 years. Extension requests for 21 units are currently under review and requests for as many as 25 more are anticipated through 2017.

[6]As of October 2009, NRC has received 18 applications for 29 new reactors. In addition to spent nuclear fuel and DOE-managed high-level waste, the nation also generates so-called greater than class C nuclear waste from the maintenance and decommissioning of nuclear power plants, from radioactive materials that were once used for food irradiation or for medical purposes, and from miscellaneous radioactive waste, such as contaminated equipment from industrial research and development. DOE, which is required to dispose of this nuclear waste, has not issued an environmental impact statement describing potential options, which could include disposal of the waste at the Yucca Mountain repository.

DOE and industry studies, three to four times the 70,000 metric tons—and possibly more—could potentially be disposed safely in Yucca Mountain, which could address current and some future waste inventories, potentially delaying the need for a second repository for several generations.

Nuclear waste has continued to accumulate at the nation's commercial and DOE nuclear facilities over the past 60 years. Facility managers must actively manage the nuclear waste by continually isolating, confining, and monitoring it to keep humans and the environment safe. Most spent nuclear fuel is stored at reactor sites, immersed in pools of water designed to cool and isolate it from the environment. With nowhere to dispose of the spent nuclear fuel, the racks holding spent fuel in the pools have been rearranged to allow for more dense storage of assemblies. Even with this re-racking, spent nuclear fuel pools are reaching their capacities. Some critics have expressed concern about the remote possibility of an overcrowded spent nuclear fuel pool releasing large amounts of radiation if an accident or other event caused the pool to lose water, potentially leading to a fire that could disperse radioactive material. As reactor operators have run out of space in their spent nuclear fuel pools, they have turned in increasing number to dry cask storage systems that generally consist of stainless steel canisters placed inside larger stainless steel or concrete casks. (See fig. 3.) NRC requires protective shielding, routine inspections and monitoring, and security systems to isolate the nuclear waste to protect humans and the environment.

Figure 3: Dry Cask Storage System for Spent Nuclear Fuel



Source: NRC.

NRC has determined that these dry cask storage systems can safely store nuclear waste, but NRC considers them to be interim measures. In 1990, NRC issued a revised waste confidence rule, stating that it had confidence that the waste generated by a reactor can be safely stored in either wet or dry storage for 30 years beyond a reactor's life, including license extensions. NRC further determined that it had reasonable assurance that safe geologic disposal was feasible and that a geologic repository would be operational by about 2025. More recently, NRC has published a notice of proposed rulemaking to revise that rule, proposing that waste generated by a reactor can be safely stored for 60 years beyond the life of a reactor and that geologic disposal would be available in 50 to 60 years beyond a reactor's life.[7] NRC is currently considering whether to republish its proposed rule to seek additional public input on certain issues. Forty-five reactor sites or former reactor sites in 30 states have dry storage facilities for their spent nuclear fuel as of June 2009, and the number of reactor sites storing spent nuclear fuel is likely to continue to grow until an alternative is implemented.

Implementing a permanent, safe, and secure disposal solution for the nuclear waste is of concern to the nation, particularly state governments and local communities, because many of the 80 sites where nuclear waste is currently stored are near large populations or major water sources or consist of shutdown reactor sites that tie up land that could be used for other purposes. In addition, states that have DOE facilities with nuclear waste storage are concerned because of possible contamination to aquifers, rivers, and other natural resources. DOE's Hanford Reservation, located near Richland, Washington, was a major component of the nation's nuclear weapons defense program from 1943 until 1989, when operations ceased. In the settlement of a lawsuit filed by the state of Washington in 2003, DOE agreed not to ship certain nuclear waste to Hanford until environmental reviews were complete. In August 2009, the U.S. government stated that the preferred alternative in DOE's environmental review would include limitations on certain nuclear waste shipments to Hanford until the process of immobilizing tank waste in glass begins,

[7] See 73 Fed. Reg. 59551-59570 (Oct. 9, 2008).

expected in 2019.[8] Moreover, some commercial and DOE sites where the nuclear waste is stored may not be able to accommodate much additional waste safely because of limited storage space or community objections. These sites will require a more immediate solution.

The nation has considered proposals to build centralized storage facilities where waste from reactor sites could be consolidated. The 1987 amendment to NWPA established the Office of the Nuclear Waste Negotiator to try to broker an agreement for a community to host a repository or interim storage facility. Two negotiators worked with local communities and Native American tribes for several years, but neither was able to conclude a proposed agreement with a willing community by January 1995, when the office's authority expired. Subsequently, in 2006 after a 9-year licensing process, a consortium of electric power companies called Private Fuel Storage obtained a NRC license for a private centralized storage facility on the reservation of the Skull Valley Band of the Goshute Indians in Utah. NRC's 20-year license—with an option for an additional 20 years—allows storage of up to 40,000 metric tons of commercial spent nuclear fuel. However, construction of the Private Fuel Storage facility has been delayed by Department of the Interior decisions not to approve the lease of tribal lands to Private Fuel Storage and declining to issue the necessary rights-of-way to transport nuclear waste to the facility through Bureau of Land Management land. Private Fuel Storage and the Skull Valley Band of Goshutes filed a federal lawsuit in 2007 to overturn Interior's decisions.

Reprocessing nuclear waste could potentially reduce, but not eliminate, the amount of waste for disposal. In reprocessing, usable uranium and plutonium are recovered from spent nuclear fuel and are used to make new fuel rods. However, current reprocessing technologies separate weapons usable plutonium and other fissionable materials from the spent nuclear fuel, raising concerns about nuclear proliferation by terrorists or

[8]The U.S. government made this statement in a letter related to a tentative settlement agreement in the lawsuit of *State of Washington v. Chu*, No. CV-08-5085-FVS (E.D. Washington, filed Nov. 26, 2008). In 2008, the state of Washington filed suit claiming DOE had violated the Tri-Party Agreement among DOE, the state, and the Environmental Protection Agency by failing to meet enforceable cleanup milestones in the agreement. On August 10, 2009, DOE and the state announced they had reached a tentative settlement, including new cleanup milestones and a 2047 completion date for certain key cleanup activities. We have questioned DOE's ability to meet this date. See GAO, *Nuclear Waste: Uncertainties and Questions about Costs and Risks Persist with DOE's Tank Waste Cleanup Strategy at Hanford*, GAO-09-913 (Washington, D.C.: Sept. 30, 2009).

enemy states. Although the United States pioneered the reprocessing technologies used by other countries, such as France and Russia, presidents Gerald Ford and Jimmy Carter ended government support for commercial reprocessing in the United States in 1976 and 1977, respectively, primarily due to proliferation concerns. Although President Ronald Reagan lifted the ban on government support in 1981, the nation has not embarked on any reprocessing program due to proliferation and cost concerns—the Congressional Budget Office recently reported that current reprocessing technologies are more expensive than direct disposal of the waste in a geologic repository.[9] DOE's Fuel Cycle Research and Development program is currently performing research in reprocessing technologies that would not separate out weapons usable plutonium, but it is not certain whether these technologies will become cost-effective.[10]

The general consensus of the international scientific community is that geologic disposal is the preferred long-term nuclear waste management alternative. Finland, Sweden, Canada, France, and Switzerland have decided to construct geologic disposal facilities, but none have yet completed any such facility, although DOE reports that Finland and Sweden have announced plans to begin emplacement operations in 2020 and 2023, respectively. Moreover, some countries employ a mix of complementary storage alternatives in their national waste management strategies, including on-site storage, consolidated interim storage, reprocessing, and geologic disposal. For example, Sweden plans to rely on on-site storage until the waste cools enough to move it to a centralized storage facility, where the waste will continue to cool and decay for an additional 30 years. This waste will then be placed in a geologic repository for disposal. France reprocesses the spent nuclear fuel, recycling usable portions as new fuel and storing the remainder for eventual disposal.

[9]Congressional Budget Office, *Costs of Reprocessing Versus Directly Disposing of Spent Nuclear Fuel; Testimony before the Committee on Energy and Natural Resources* (Washington, D.C.: Nov. 14, 2007).

[10]DOE changed the name of this program from the Advanced Fuel Cycle Initiative to the Fuel Cycle Research and Development program in its fiscal year 2010 budget submission.

The Yucca Mountain Repository Would Provide a Permanent Solution for Nuclear Waste, but Its Implementation Faces Challenges and Significant Upfront Costs

The Yucca Mountain repository—mandated by NWPA, as amended—would provide a permanent nuclear waste management solution for the nation's current inventory of about 70,000 metric tons of waste. According to DOE and industry studies, the repository potentially could be a disposal site for three to four times that amount of waste. However, the repository lacks the support of the administration and the state of Nevada, and faces regulatory and other challenges. Our analysis of DOE's cost projections found that the Yucca Mountain repository would cost from $41 billion to $67 billion (in 2009 present value) for disposing of 153,000 metric tons of nuclear waste.[11] Most of these costs are up-front capital costs. However, once the Yucca Mountain repository is closed—in 2151 for our 153,000-metric-ton model—it is not expected to incur any significant additional costs, according to DOE.

As Designed, the Yucca Mountain Repository Would Be a Permanent Solution and Would Reduce the Uncertainty Associated with Future Nuclear Waste Safety

The Yucca Mountain repository is designed to isolate nuclear waste in a safe and secure environment long enough for the waste to degrade into a form that is less harmful to humans and the environment. As nuclear waste ages, it cools and decays, becoming less radiologically dangerous. In October 2008, after years of legal challenges, the Environmental Protection Agency (EPA) promulgated standards that require DOE to ensure that radioactive releases from the nuclear waste disposed of at Yucca Mountain do not harm the public for 1 million years.[12] This is because some waste components, such as plutonium 239, take hundreds of thousands of years to decay into less harmful materials. To meet EPA's standards and keep the waste safely isolated, DOE's license application proposes the use of both natural and engineered barriers. Key natural barriers of Yucca Mountain include its dry climate, the depth and isolation

[11]Our cost range for a permanent repository differs from DOE's most recent estimate of $96 billion for the following reasons: First, our cost range is in 2009 present value, while DOE uses 2007 constant dollars, which are not discounted. Our present value analysis reflects the time value of money—costs incurred in the future are worth less today—so that streams of future costs become smaller. Second, our cost range does not include about $14 billion in previously incurred costs. Third, our cost range is for 153,000 metric tons of nuclear waste while DOE's estimated cost is for 122,100 metric tons. Finally, we use a range while DOE provides a point estimate.

[12]The Energy Policy Act of 1992 directed EPA to base its health standards on a National Academy of Sciences study of the health issues related to radioactive releases. NRC has promulgated rules based on EPA's October 2008 standards that require the Yucca Mountain repository to limit the annual radiation dose of the public to at most 15 millirem for the first 10,000 years after disposal and at most 100 millirem from 10,001 years to 1 million years after disposal. In contrast, the average American is exposed to about 360 millirem of radiation annually, mainly from natural background sources.

of the Death Valley aquifer in which the mountain resides, its natural physical shape, and the layers of thick rock above and below the repository that lie 1,000 feet below the surface of the mountain and 1,000 feet above the water table. Key engineered barriers include the solid nature of the nuclear waste; the double-shelled transportation, aging, and disposal canisters that encapsulate the waste and prevent radiation leakage; and drip shields that are composed of corrosion-resistant titanium to ward off any dripping water inside the repository for many thousands of years.

The construction of a geologic repository at Yucca Mountain would provide a permanent solution for nuclear waste that could allow the government to begin taking possession of the nuclear waste in the near term—about 10 to 30 years. The nuclear power industry sees this as an important consideration in obtaining the public support necessary to build new nuclear power reactors. The industry is interested in constructing new nuclear power reactors because, among other reasons, of the growing demand for electricity and pressure from federal and state governments to reduce reliance on fossil fuels and curtail carbon emissions. Some electric power companies see nuclear energy as an important option for noncarbon emitting power generation. According to NRC, 18 electric power companies have filed license applications to construct 29 new nuclear reactors.[13] Nuclear industry representatives, however, have expressed concerns that investors and the public will not support the construction of new nuclear power reactors without a final safe and secure disposition pathway for the nuclear waste, particularly if that waste is generated and stored near major waterways or urban centers. Moreover, having a permanent disposal option may allow reactor operators to thin-out spent nuclear fuel assemblies from densely packed spent fuel pools, potentially reducing the risk of harm to humans or the environment in the event of an accident, natural disaster, or terrorist event.

In addition, disposal is the only alternative for some DOE and commercial nuclear waste—even if the United States decided to reprocess the waste—because it contains nuclear waste residues that cannot be used as nuclear reactor fuel. This nuclear waste has no safe, long-term alternative other than disposal, and the Yucca Mountain repository would provide a near-term, permanent disposal pathway for it. Moreover, DOE has agreed to

[13]As of October 2, 2009, NRC had suspended or deferred five applications to build and operate six reactors at the request of the applicants.

remove spent nuclear fuel from at least two states by certain dates or face penalties. Specifically, DOE has an agreement with Colorado stating that if the spent nuclear fuel at Fort St. Vrain is not removed by January 1, 2035, the government will, subject to certain conditions, pay the state $15,000 per day until the waste is removed. In addition, the state of Idaho sued DOE to remove inventories of spent nuclear fuel stored at DOE's Idaho National Laboratory. Under the resulting settlement DOE agreed to (1) remove the spent nuclear fuel by January 1, 2035, or incur penalties of $60,000 per day and (2) curtail or suspend future shipments of spent nuclear fuel to Idaho.[14] Some of the spent nuclear fuel stored at the Idaho National Laboratory comes from refueling the U.S. Navy's submarines and aircraft carriers, all of which are nuclear powered. Special facilities are maintained at the Idaho National Laboratory to examine naval spent nuclear fuel to obtain information for improving future fuel performance and to package the spent nuclear fuel following examination to make it ready for rail shipment to its ultimate destination. According to Navy officials, refueling these warships, which necessitates shipment of naval spent nuclear fuel from the shipyards conducting the refuelings to the Idaho National Laboratory, is part of the Navy's national security mission. Consequently, curtailing or suspending shipments of spent nuclear fuel to Idaho raises national security concerns for the Navy.

The Yucca Mountain repository would help the government fulfill its obligation under NWPA to electric power companies and ratepayers to take custody of the commercial spent nuclear fuel and provide a permanent repository using the Nuclear Waste Fund. When DOE missed its 1998 deadline to begin taking custody of the waste, owners of spent fuel with contracts for disposal services filed lawsuits asking the courts to require DOE to fulfill its statutory and contractual obligations by taking custody of the waste. Though a court decided that it would not order DOE to begin taking custody of the waste, the courts have, in subsequent cases, ordered the government to compensate the utilities for the cost of storing the waste. DOE projected that, based on a 2020 date for beginning operations at Yucca Mountain, the government's liabilities from the 71 lawsuits filed by electric power companies could sum to about $12.3 billion, though the outcome of pending and future litigation could

[14]The penalties in the settlement agreement specifically apply to spent nuclear fuel and not to other high-level waste. However, the agreement specifies that DOE must have the other high-level waste treated and ready for shipment out of Idaho for disposal by 2035. DOE officials acknowledged that Idaho could take further court action if its milestones toward meeting these goals are not being met.

substantially affect the ultimate total liability.[15] DOE estimates that the federal government's future liabilities will average up to $500 million per year. Furthermore, continued delays in DOE's ability to take custody of the waste could result in additional liabilities. Some experts noted that without immediate plans for a permanent repository, reactor operators and ratepayers may demand that the Nuclear Waste Fund be refunded.[16]

Finally, disposing of the nuclear waste now in a repository facility would reduce the uncertainty about the willingness or the ability of future generations to monitor and maintain multiple surface waste storage facilities and would eliminate the need for any future handling of the waste. As a 2001 report of the National Academies noted, continued storage of nuclear waste is technically feasible only if those responsible for it are willing and able to devote adequate resources and attention to maintaining and expanding the storage facilities, as required to keep the waste safe and secure.[17] DOE officials noted that the waste packages at Yucca Mountain are designed to be retrievable for more than 100 years after emplacement, at which time DOE would begin to close the repository, allowing future generations to consider retrieving spent nuclear fuel for reprocessing or other uses. However, the risks and costs of retrieving the nuclear waste from Yucca Mountain are uncertain because planning efforts for retrieval are preliminary. Once closed, Yucca Mountain will require minimal monitoring and little or no maintenance, and all future controls will be passive.[18] Some experts stated that the current generation has a moral obligation to not pass on to future

[15]As of July 2009, of the 71 lawsuits filed by electric power companies, 51 cases were pending either in the Court of Federal Claims or in the Court of Appeals for the Federal Circuit, 10 had been settled, 6 were voluntarily withdrawn, and 4 had been litigated through final unappealable judgment.

[16]DOE estimated the Nuclear Waste Fund at about $23 billion in June 2009, some of which is interest that has accrued. DOE is required to invest the Nuclear Waste Fund in U.S. Treasury securities, resulting in the government paying about $11.2 billion interest to the fund. Both the principal and the interest might be returned, if the fund is returned to the electric power companies.

[17]National Research Council of the National Academies*, Disposition of High-Level Waste and Spent Nuclear Fuel: The Continuing Societal and Technical Challenges*, (Washington, D.C., 2001).

[18]Section 801 (c) of the Energy Policy Act of 1992 requires DOE to provide indefinite oversight to prevent any activity at the site that poses an unreasonable risk of (1) breaching the repository's engineered or geologic barriers or (2) increasing the exposure of the public to radiation beyond allowable limits. Pub. L. No. 102-486, 106 Stat. 2776, 2921-2922.

generations the extensive technical and financial responsibilities for managing nuclear waste in surface storage.

Yucca Mountain Faces Many Challenges, Including a Lack of Key Support and License Approval

There are many challenges to licensing and constructing the Yucca Mountain repository, some of which could delay or potentially terminate the program. First, in March 2009, the Secretary of Energy stated that the administration planned to terminate the Yucca Mountain repository and to form a panel of experts to review alternatives. During the testimony, the Secretary stated that Yucca Mountain would not be considered as one of the alternatives. The administration's fiscal year 2010 budget request for Yucca Mountain was $197 million, which is $296 million less than what DOE stated it needs to stay on its schedule and open Yucca Mountain by 2020.

In July 2009 letters to DOE, the Nuclear Energy Institute and the National Association of Regulatory Utility Commissioners raised concerns that, despite the announced termination of Yucca Mountain, DOE still intended on collecting fees for the Nuclear Waste Fund.[19] The letters requested that DOE suspend collection of payments to the Nuclear Waste Fund. Some states have raised similar concerns and legislators have introduced legislation that could hold payments to the Nuclear Waste Fund until DOE begins operating a federal repository.[20]

Nevertheless, NWPA still requires DOE to pursue geologic disposal at Yucca Mountain. If the administration continues the licensing process for Yucca Mountain, DOE would face a variety of other challenges in licensing and constructing the repository. Many of these challenges—though unique to Yucca Mountain—might also apply in similar form to other future repositories, should they be considered.

One of the most significant challenges facing DOE is to satisfy NRC that Yucca Mountain meets licensing requirements, including ensuring the repository meets EPA's radiation standards over the required 1 million year time frame, as implemented by NRC regulation. For example, NRC's

[19]The Nuclear Energy Institute represents the nuclear power industry and the National Association of Regulatory Utility Commissioners represents state public utility commissions that regulate the electric power industry.

[20]Minnesota House File No. 894, introduced February 16, 2009, and Michigan Senate Concurrent Resolution No. 8, introduced March 25, 2009.

regulations require that DOE model its natural and engineered barriers in a performance assessment, including how the barriers will interact with each other over time and how the repository will meet the standards even if one or more barriers do not perform as expected. NRC has stated that there are uncertainties inherent in the understanding of the performance of the natural and engineered barriers and that demonstrating a reasonable expectation of compliance requires the use of complex predictive models supported by field data, laboratory tests, site-specific monitoring, and natural analog studies. The Nuclear Waste Technical Review Board has also stated that the performance assessment may be "the most complex and ambitious probabilistic risk assessment ever undertaken" and the Board, as well as other groups or individuals, have raised technical concerns about key aspects of the engineered or natural barriers in the repository design.

DOE and NRC officials also stated that budget constraints raise additional challenges. DOE officials told us that past budget shortfalls and projected future low budgets for the Yucca Mountain repository create significant challenges in DOE's ability to meet milestones for licensing and for responding to NRC's requests for additional information related to the license application. In addition, NRC officials told us budget shortfalls have constrained their resources. Staff members they originally hired to review DOE's license application have moved to other divisions within NRC or have left NRC entirely. NRC officials stated that the pace of the license review is commensurate with funding levels. Some experts have questioned whether NRC can meet the maximum 4-year time requirement stipulated in NWPA for license review and have pointed out that the longer the delays in licensing Yucca Mountain, the more costly and politically vulnerable the effort becomes.

In addition, the state of Nevada and other groups that oppose the Yucca Mountain repository have raised technical points, site-specific concerns, and equity issues and have taken steps to delay or terminate the repository. For example, Nevada's Agency for Nuclear Projects questioned DOE's reliance on engineered barriers in its performance assessment, indicating that too many uncertainties exist for DOE to claim human-made systems will perform as expected over the time frames required. In addition, the agency reported that Yucca Mountain's location near seismic and volcanic zones creates additional uncertainty about DOE's ability to predict a recurrence of seismic or volcanic events and to assess the performance of its waste isolation barriers should those events occur some time during the 1-million-year time frame. The agency also has questioned whether Yucca Mountain is the best site compared with other

locations and has raised issues of equity, since Nevada is being asked to accept nuclear waste generated in other states. In addition to the Agency for Nuclear Projects' issues, Nevada has taken other steps to delay or terminate the project. For example, Nevada has denied the water rights DOE needs for construction of a rail spur and facility structures at Yucca Mountain. DOE officials told us that constructing the rail line or the facilities at Yucca Mountain without those water rights will be difficult.

Based on DOE's Cost Estimates, Yucca Mountain Will Likely Cost from $41 Billion to $67 Billion for 153,000 Metric Tons of Nuclear Waste, but Costs Could Increase

Our analysis of DOE's cost estimates found that (1) a 70,000 metric ton repository is projected to cost from $27 to $39 billion in 2009 present value over 108 years and (2) a 153,000 metric ton repository is projected to cost from $41 to $67 billion and take 35 more years to complete. These estimated costs include the licensing, construction, operation, and closure of Yucca Mountain for a period commensurate with the amount of waste. Table 1 shows each scenario with its estimated cost range over time.

Table 1: Estimated Cost of the Yucca Mountain Scenarios

Dollars in billions

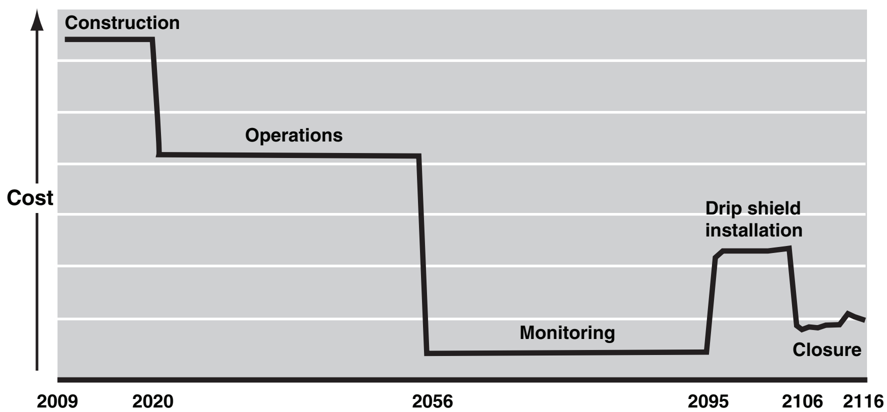
Amount of nuclear waste disposed	Time period covered[a]	Present value estimate range[a]
70,000 metric tons	2009 to 2116 (108 years)	$27 to $39
153,000 metric tons	2009 to 2151 (143 years)	$41 to $67

Source: GAO analysis based on DOE data.

[a]These costs are in 2009 present value and thus different than the values presented by DOE which are in constant 2007 dollars. Also, these costs do not include more than $14 billion, in constant fiscal year 2009 dollars, that DOE spent from 1983 through 2008 for the Yucca Mountain repository. In addition, we did not include potential schedule delays and costs associated with licensing. DOE reported that each year of delay could cost DOE about $373 million in constant 2009 dollars.

As shown in figure 4, the Yucca Mountain repository costs are expected to be high during construction, followed by reduced, but consistent costs during operations, substantially reduced costs for monitoring, then a period of increased costs for installation of the drip shields, and finally costs tapering off for closure. Once the drip shields are installed, by design, the waste packages will no longer be retrievable. After closure, Yucca Mountain is not expected to incur any significant additional costs.

Figure 4: Cost Profile for the Yucca Mountain Repository, Assuming 70,000 Metric Tons



Source: GAO analysis of DOE data.

Costs for the construction of a repository, regardless of location, could increase based on a number of different scenarios, including delays in license application, funding shortfalls, and legal or technical issues that cause delays or changes in plans. For example, we asked DOE to assess the cost of a year's delay in license application approval from the current 3 years to 4 years, the maximum allowed by NWPA. DOE officials told us that each year of delay would cost DOE about $373 million in constant 2009 dollars. Although the experts with whom we consulted did not agree on how long the licensing process for Yucca Mountain might take, several experts told us that the 9 years it took Private Fuel Storage to obtain its license was not unreasonable. This licensing time frame may not directly apply to the Yucca Mountain repository because the repository has a significantly different licensing process and regulatory scheme, including extensive pre-licensing interactions, a federal funding stream, and an extended compliance period and, because of the uncertainties, could take shorter or longer than the Private Fuel Storage experience. A nine-year licensing process for construction authorization would add an estimated $2.2 billion to the cost of the repository, mostly in costs to maintain current systems, such as project support, safeguards and security, and its licensing support network. In addition to consideration of the issuance of a construction authorization, NRC's repository licensing process involves two additional licensing actions necessary to operate and close a repository, each of which allows for public input and could potentially adversely affect the schedule and cost of the repository. The second action is the consideration of an updated DOE application for a license to receive and possess high-level radioactive waste. The third action is the

consideration of a DOE application for a license amendment to permanently close the repository. Costs could also increase if unforeseen technical issues developed. For example, some experts told us that the robotic emplacement of waste packages could be difficult because of the heat and radiation output from the nuclear waste, which could impact the electronics on the machinery. DOE officials acknowledged the challenges and told us the machines would have to be shielded for protection. They noted, however, that industry has experience with remote handling of shielded robotic machinery and DOE should be able to use that experience in developing its own machinery.

The responsibility for Yucca Mountain's costs would come from the Nuclear Waste Fund and taxpayers through annual appropriations. NWPA created the Nuclear Waste Fund as a mechanism for the nuclear power industry to pay for its share of the cost for building and operating a permanent repository to dispose of nuclear waste. NWPA also required the federal taxpayers to pay for the portion of permanent repository costs for DOE-managed spent nuclear fuel and high-level waste. DOE has responsibility for determining on an annual basis whether fees charged to industry to finance the Nuclear Waste Fund are sufficient to meet industry's share of costs. As part of that process, DOE developed a methodology in 1989 that uses the total system life cycle cost estimate as input for determining the shares of industry and the federal government by matching projected costs against projected assets. The most recent published assessment, published in July 2008, showed that 80.4 percent of the disposal costs would come from the Nuclear Waste Fund and 19.6 percent would come from appropriations for the DOE-managed spent nuclear fuel and high-level waste.

In addition, the Department of the Treasury's judgment fund will pay the government's liabilities for not taking custody of the nuclear waste in 1998, as required by DOE's contract with industry. Based on existing judgments and settlements, DOE has estimated these costs at $12.3 billion through 2020 and up to $500 million per year after that, though the outcome of pending litigation could substantially affect the government's ultimate liability. The Department of Justice has also spent about $150 million to defend DOE in the litigation.

We Identified Two Nuclear Waste Management Alternatives and Developed Cost Models by Consulting with Experts

We used input from experts to identify two nuclear waste management alternatives that could be implemented if the nation does not pursue disposal at Yucca Mountain—centralized storage and continued on-site storage, both of which could be implemented with final disposal, according to experts. To understand the implications and likely assumptions of each alternative, as well as the associated costs for the component parts, we systematically solicited facts, advice, and opinions from experts in nuclear waste management. Finally, we used the data and assumptions that the experts provided to develop large-scale cost models that estimate ranges of likely total costs for each alternative.

We Consulted with Experts to Identify and Develop Assumptions for Two Generic Alternatives to Analysis

To identify waste management alternatives that could be implemented if the waste is not disposed of at Yucca Mountain, we solicited facts, advice, and opinions from nuclear waste management experts. Specifically, we interviewed dozens of experts from DOE, NRC, the Nuclear Energy Institute, the National Association of Regulatory Utility Commissioners, the National Conference of State Legislatures, and the State of Nevada Agency for Nuclear Projects. We also reviewed documents they provided or referred us to.

Based on this information, we chose to analyze (1) centralized interim dry storage and (2) on-site dry storage (both interim and long-term). Centralized storage has been attempted to varying degrees in the United States, and on-site storage has become the country's status quo. Consequently, the experts believe these two alternatives are currently among the most likely for this country in the near-term, in conjunction with final disposal in the long-term. The experts also told us that current nuclear waste reprocessing technologies raise proliferation concerns and are not considered commercially feasible, but they noted that reprocessing has future potential as a part of the nation's nuclear waste management strategy. Because nuclear waste is not reprocessed in this country, we found a lack of sufficient and reliable data to provide meaningful analysis for this alternative. Experts have largely dismissed other alternatives that have been identified, such as disposal of waste in deep boreholes, because of cost or technical constraints.

We developed a set of key assumptions to establish the scope of our alternatives by initially consulting with a small group of nuclear waste management experts. For example, we asked the experts about how many storage sites should be used and whether waste would have to be repackaged. These discussions occurred in an iterative manner—we followed up with experts with specific expertise to refine our assumptions

as we learned more. Based on this input, we formulated several key assumptions and defined the alternatives in a generic manner by taking into account some, but not all, of the complexities involved with nuclear waste management (see table 2). We made this choice because experts advised us that trying to consider all of the variability among reactor sites would result in unmanageable models since each location where nuclear waste is currently stored has a unique set of environmental, management, and regulatory considerations that affect the logistics and costs of waste management. For example, reactor sites use different dry cask storage systems with varying costs that require different operating logistics to load the casks.

Table 2: Key Assumptions Used to Define Alternatives

Centralized storage	
Type of storage	Conventional dry cask storage (for commercial spent nuclear fuel).
Number of sites	Two centralized interim storage sites, located in different geographic regions of the country.
Reactor operations	All currently operating reactors receive a 20-year license extension and continue operating until the extensions expire. Reactors will be decommissioned when operations cease, and only spent nuclear fuel dry storage will remain on site.
Transportation	Transportation to the centralized site will be via rail using dedicated trains.
Repackaging	Waste will not be repackaged at the centralized facilities.
Final disposition[a]	After 100 years, the waste will be disposed of in a geologic repository.
On-site storage	
Type of storage	Conventional dry cask storage (for commercial spent nuclear fuel).
Number of sites	Commercial spent nuclear fuel will be stored on independent spent fuel storage installations at 75 reactor sites, which includes operating reactor sites, decommissioned reactor sites, and the Morris facility.[b] DOE high-level waste and spent nuclear fuel will remain at five current sites.[c] DOE spent nuclear fuel will be moved to dry storage. DOE high-level waste will be vitrified and stored in facilities like the Glass Waste Storage Building at the Savannah River Site.
Reactor operations	All currently operating reactors receive a 20-year license extension and continue operating until the extensions expire. Reactors will be decommissioned when operations cease, and only spent nuclear fuel dry storage will remain on site.
Transportation	Waste will not be transported between reactor sites.
Repackaging	Dry cask storage systems will need to be replaced after 100 years, requiring repackaging into new inner canisters and outer casks. Only our 500-year on-site storage model assumes repackaging.
Final disposition or long-term management[c]	We analyzed two final disposition scenarios: The waste will be disposed of in a geologic repository after 100 years or the waste will remain on site for 500 years and be repackaged every 100 years.

Source: GAO analysis based on expert-provided data.

[a]We analyzed some scenarios associated with these alternatives that did not include final disposition of the waste.

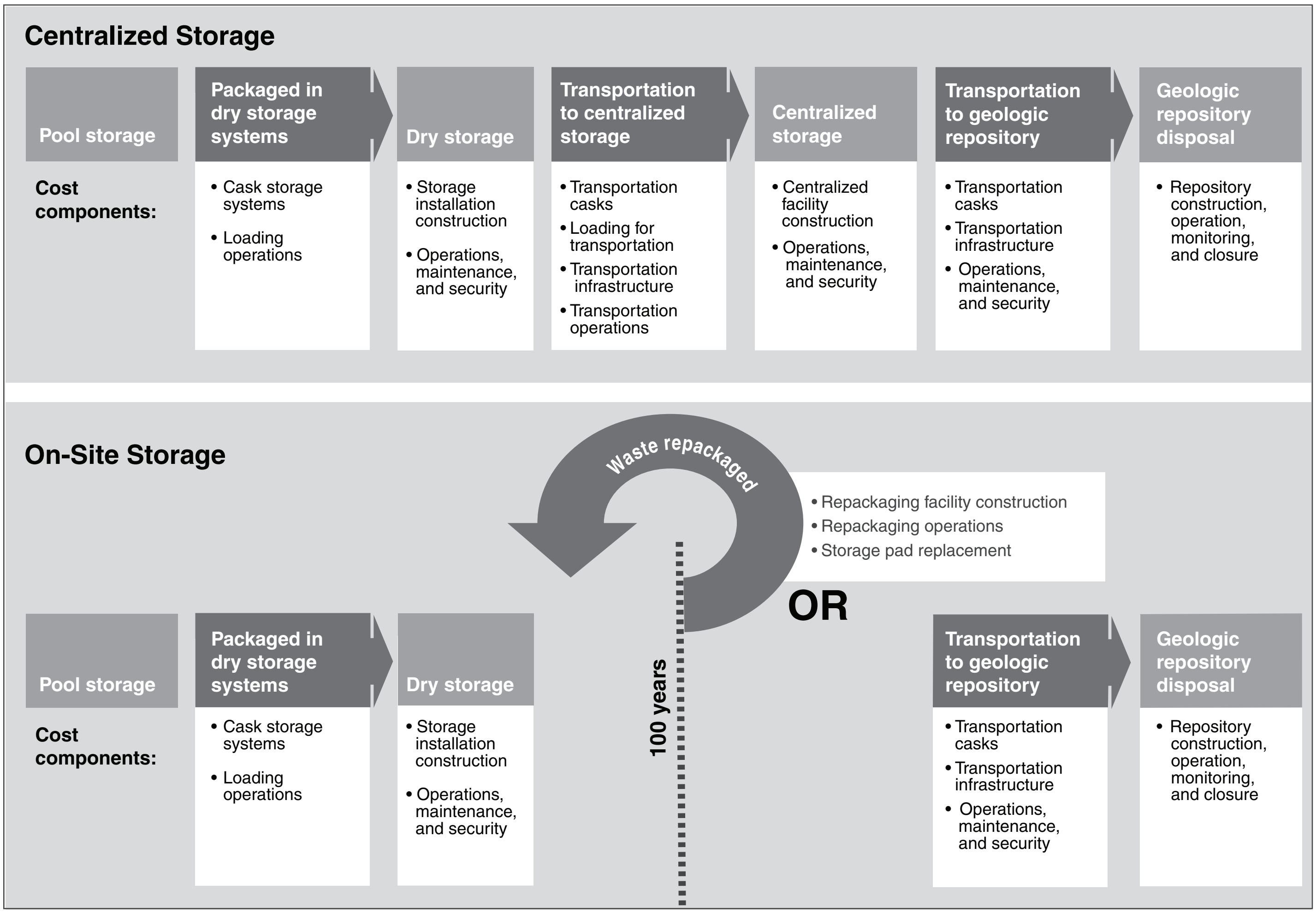
[b]The Morris facility is an independent spent nuclear fuel storage installation located in Illinois that is operated by General Electric Corporation, which originally intended to operate a fuel reprocessing plant at the site. The Morris facility is the only spent nuclear fuel pool licensed by NRC that is not at a reactor site.

[c]Hanford Reservation, Washington; Idaho National Laboratory, Idaho; Fort St. Vrain, Colorado; West Valley, New York; and Savannah River Site, South Carolina.

In addition, there were some instances in which we made assumptions that, while not entirely realistic, were necessary to keep our alternatives generic and distinct from one another. For example, some electric power companies would likely consolidate nuclear waste from different locations by transporting it between reactor sites, but to keep the on-site storage alternative generic and distinct from the centralized storage alternative, we assumed that there would be no consolidation of waste. These simplifying assumptions make our alternatives hypothetical and not entirely representative of their real-world implementation.

We also consulted with experts to formulate more specific assumptions about processes that reflect the sequence of activities that would occur within each alternative (see fig. 5). In addition, we identified the components of these processes that have associated costs. For example, one of the processes associated with both alternatives is packaging the nuclear waste in dry storage canisters from the pools of water where they are stored. The component costs associated with this process include the dry storage canisters and operations to load the spent nuclear fuel into the canisters.

Figure 5: Process Assumptions and Cost Components for Hypothetical Nuclear Waste Management Alternatives



Source: GAO analysis based on expert-provided data.

We then began to gather data on specific processes and component costs, such as the kind of cask systems we would use in our model and their cost. We gathered initial data from a core group of experts with specialized knowledge in different aspects of nuclear waste management, such as cask systems, waste loading operations, and transportation. We then solicited comments on the initial data from a broader group of experts using a data collection instrument that asked specific questions about how reasonable the data were. We received almost 70 sets of comments and used them to refine or modify our assumptions and component costs and develop the input data that we would use to estimate

the overall costs of the alternatives. (See app. I for additional information about our scope and methodology, app. II for our methodology for soliciting comments from nuclear waste management experts, and app. III for these experts.)

We Developed Cost Ranges for Each Alternative Using Large-scale Cost Models that Addressed Uncertainties and Discounted Future Costs

To generate cost ranges for the centralized storage and on-site storage alternatives, we developed four large-scale cost models that analyzed the costs for each alternative of storing 70,000 metric tons and 153,000 metric tons of nuclear waste and created scenarios within these models to analyze different storage durations and final dispositions. (See table 3.) We generated cost ranges for each alternative for storing 153,000 metric tons of waste for 100 years followed by disposal in a geologic repository. We also generated cost ranges for each alternative of storing 70,000 metric tons and 153,000 metric tons of nuclear waste for 100 years, and for storing 153,000 metric tons of waste on site for 500 years without including the cost of subsequent disposal in a geologic repository. For each of the models, which rely upon data and assumptions provided by nuclear waste management experts, the cost range was based on the annual volume of commercial spent nuclear fuel that became ready to be packaged and stored in each year.[21] In general, each model started in 2009 by annually tracking costs of initial packaging and related costs for the first 100 years and for every 100 years thereafter if the waste was to remain on site and be repackaged. Since our models analyzed only the costs associated with storing commercial nuclear waste management, we augmented them with DOE's cost data for (1) managing its spent nuclear fuel and high-level waste and (2) constructing and operating a permanent repository. Specifically, we used DOE's estimated costs for the Yucca Mountain repository to represent cost for a hypothetical permanent repository.[22]

[21]NWPA caps the amount of nuclear waste that can be disposed of at Yucca Mountain at 70,000 metric tons. The estimated amount of current waste plus additional commercial spent nuclear fuel that would be generated if all currently operating commercial reactors received license extensions is 153,000 metric tons. Our analysis did not consider new reactors because of the uncertainty if or when new reactors would be built, how many would be built, and their impact on waste streams.

[22]We excluded historical costs for the Yucca Mountain repository because these costs represent challenges unique to Yucca Mountain and may not be applicable to a future repository. However, the bulk of future cost for construction, operation, and closure may be representative of a new repository.

Table 3: Models and Scenarios Used for Cost Ranges

Model		Scenario	
Nuclear waste management alternative	**Waste volume (metric tons)**	**Storage duration (years)**	**Final disposition or long-term management**
On-site storage	153,000	100	None
		100	Permanent repository
		500	Waste repackaged every 100 years
On-site storage	70,000	100	None
Centralized storage	153,000	100	None
		100	Permanent repository
Centralized storage	70,000	100	None

Source: GAO analysis.

One of the inherent difficulties of analyzing the cost of any nuclear waste management alternative is the large number of uncertainties that need to be addressed. In addition to general uncertainty about the future, there is uncertainty because of the lack of knowledge about the waste management technologies required, the type of waste and waste management systems that individual reactors will eventually employ, and cost components that are key inputs to the models and could occur over hundreds or thousands of years. Given these numerous uncertainties, it is not possible to precisely determine the total costs of each alternative. However, much of the uncertainty that we could not easily capture within our models can be addressed through the use of several alternative models and scenarios. As shown in table 3, we developed two models for each alternative to address the uncertainty regarding the total volume of waste for disposal. We then developed different scenarios within each model to address different time frames and disposal paths. Furthermore, we used a risk analysis modeling technique that recognized and addressed uncertainties in our data and assumptions. Given the different possible scenarios and uncertainties, we generated ranges, rather than point estimates, for analyzing the cost of each alternative.

One of the most important uncertainties in our analysis was uncertainty over component costs. To address this, we used a commercially available risk analysis software program that enabled us to model specific

uncertainties associated with a large number of cost inputs and assumptions. Using a Monte Carlo simulation process,[23] the program explores a wide range of values, instead of one single value, for each cost input and estimates the total cost. By repeating the calculations thousands of times with a different set of randomly chosen input values, the process produces a range of total costs for each alternative and scenario. The process also specifies the likelihood associated with values in the estimated range.

Another inherent difficulty in estimating the cost of nuclear waste management alternatives is the fact that the costs are spread over hundreds or thousands of years. The economic concept of discounting is central to such long-term analysis because it allows us to convert costs that occur in the distant future to present value—equivalent values in today's dollars. Although the concept of discounting is an accepted and standard methodology in economics, the concept of discounting values over a very distant future—known as "intergenerational discounting"—is still subject to considerable debate. Furthermore, no consensus exists among economists regarding the exact value of the discount rate that should be used to discount values that are spread over many hundreds or thousands of years.

To develop an appropriate discounting methodology and to choose the discount rates for our analysis, we reviewed a number of economic studies published in peer-reviewed journals that addressed intergenerational discounting. Based on our review, we designed a discounting methodology for use in our models. Because our review did not find a consensus on discount rates, we used a range of values for discount rates that we developed based on the economic studies we reviewed, rather than using one single rate. Consequently, because we used ranges for the discount rate along with the Monte Carlo simulation process, the present value of estimated costs does not depend on one single discount rate, but rather reflect a range of discount rate values taken from peer-reviewed studies. (See app. IV for details of our modeling and discounting methodologies, assumptions, and results.)

[23]We used a commercially available risk analysis program called Crystal Ball for our Monte Carlo simulation. Crystal Ball is a commonly used spreadsheet-based software for predictive modeling and forecasting.

Centralized Storage Would Provide a Near-Term Alternative, Allowing Other Options to Be Studied, but Faces Implementation Challenges

Centralized storage would provide a near-term alternative for managing nuclear waste, allowing the government to begin taking possession of the waste within approximately the next 30 years, and giving additional time for the nation to consider long-term waste management options. However, centralized storage does not preclude the need for final disposal of the waste. In addition, centralized storage faces several implementation challenges including that DOE (1) lacks statutory authority to provide centralized storage under NWPA, (2) is expected to have difficulty finding a location willing to host a centralized storage facility, and (3) faces potential transportation risks. The estimated cost of implementing centralized storage for 100 years ranges from $15 billion to $29 billion for 153,000 metric tons of nuclear waste, and the total cost ranges from $23 billion to $81 billion if the nuclear waste is centrally stored and then disposed in a geologic repository.

Centralized Storage Would Provide a Near-Term Alternative to Managing Nuclear Waste but Does Not Eliminate the Need for Final Disposal

As the administration re-examines the Yucca Mountain repository and national nuclear waste policy, centralized dry cask storage could provide a near-term alternative for managing the waste that has accumulated and will continue to accumulate. This would provide additional time—NRC has stated that spent nuclear fuel storage is safe and environmentally acceptable for a period on the order of 100 years—to consider other long-term options that may involve alternative policies and new technologies and allow some flexibility for their implementation. For example, centralized storage would maintain nuclear waste in interim dry storage configurations so that it could be easily accessible for reprocessing in case the nation decided to pursue reprocessing as a waste management option and developed technologies that address current proliferation and cost concerns. In fact, reprocessing facilities could be built near or adjacent to centralized facilities to maximize efficiencies. However, even with reprocessing, some of the spent nuclear fuel and high-level waste in current inventories would require final disposal.

Centralized storage would consolidate the nation's nuclear waste after reactors are decommissioned, thereby decreasing the complexity of securing and overseeing the waste and increasing the efficiency of waste storage operations. This alternative would remove nuclear waste from all DOE sites and nine shutdown reactor sites that have no operations other than nuclear waste storage, allowing these sites to be closed. Some of these storage sites occupy land that potentially could be used for other purposes, imposing an opportunity cost on states and communities that no longer receive the benefits of electricity generation from the reactors. To compensate for this loss, industry officials noted that at least two states

where decommissioned sites are located have tried to raise property taxes on the sites, and at one site, the state collects a per cask fee for storage. In addition, the continued storage of nuclear waste at decommissioned sites can cost the power companies between about $4 million and $8 million per year, according to several experts.

Centralized storage could allow reactor operators to thin-out spent nuclear fuel assemblies from densely packed spent fuel pools and may also prevent operating reactors from having to build the additional dry storage capacity they would need if the nuclear waste remained on site. According to an industry official, 28 reactor sites could have to add dry storage facilities over the next 10 years in order to maintain a desired capacity in their storage pools. These dry storage facilities could cost about $30 million each, but this cost would vary widely by site. In addition, some current reactor sites use older waste storage systems and are near large cities or large bodies of fresh water used for drinking or irrigation. Although NRC's licensing and inspection process is designed to ensure that these existing facilities appropriately protect public health and safety, new centralized facilities could use state-of-the-art design technology and be located in remote areas with fewer environmental hazards, in order to protect public health and enhance safety.

Finally, if DOE uses centralized facilities to store commercial spent nuclear fuel, this alternative could allow DOE to fulfill its obligation to take custody of the commercial spent nuclear fuel until a long-term strategy is implemented. As a result, DOE could curtail its liabilities to the electric power companies, potentially saving the government up to $500 million per year after 2020, as estimated by DOE. The actual impact of centralized storage on the amount of the liabilities would depend on several factors, including when centralized storage is available, whether reactor sites had already built on-site dry storage facilities for which the government may be liable for a portion of the costs, how soon waste could be transported to a centralized site, and the outcome of pending litigation that may affect the government's total liability. DOE estimates that if various complex statutory, regulatory, siting, construction, and financial issues were expeditiously resolved, a centralized facility to accept nuclear waste could begin operations as early as 6 years after its development began. However, a centralized storage expert estimated that the process from site selection until a centralized facility opens could take between 17 and 33 years.

Although centralized storage has a number of positive attributes, it provides only an interim alternative and does not eliminate the need for

final disposal of the nuclear waste. To keep the waste safe and secure, a centralized storage facility relies on active institutional controls, such as monitoring, maintenance, and security. Over time, the storage systems may degrade and institutional controls may be disrupted, which could result in increased risk of radioactive exposure to humans or the environment. For example, according to several experts on dry cask systems, the vents on the casks—which allow for passive cooling—must be periodically inspected to ensure no debris clogs them, particularly during the first several decades when the spent nuclear fuel is thermally hot. If the vents become clogged, the temperature in the canister could rise, which could impact the life of the dry cask storage system. Over a longer time frame, concrete on the exterior casks could degrade, requiring more active maintenance. Although some experts stated that the risk of radiation being released into the environment may be low, such risks can be avoided by permanently isolating the waste in a manner that does not require indefinite, active institutional controls, such as disposal in a geologic repository.

Legal and Community Challenges Contribute to the Complexity of Implementing Centralized Storage

A key challenge confronting the centralized storage alternative is the lack of authority under NWPA for DOE to provide such storage. Provisions in NWPA that allow DOE to arrange for centralized storage have either expired or are unusable because they are tied to milestones in repository development that have not been met. For example, NWPA authorized DOE to provide temporary storage for a limited amount of spent nuclear fuel until a repository was available, but this authority expired in 1990. Some industry representatives have stated that DOE still has the authority to accept and store spent nuclear fuel under the Atomic Energy Act of 1954, as amended, but DOE asserts that NWPA limits its authority under the Atomic Energy Act.[24] In addition, NWPA provided authority for DOE to site, construct, and operate a centralized storage facility, but such a facility could not be constructed until NRC authorized construction of the Yucca Mountain repository, and the facility could only store up to 10,000 metric

[24]DOE acknowledged that the Atomic Energy Act of 1954, as amended, does provide the authority for DOE to accept and store spent nuclear fuel under certain circumstances, which DOE has used in the past to accept and store spent nuclear fuel. For example, pursuant to the Atomic Energy Act authority, DOE has accepted and stored U.S.-supplied spent nuclear fuel from foreign reactors, as well as damaged spent nuclear fuel from the Three Mile Island reactor site. However, DOE asserts that the NWPA's detailed statutory scheme limits its authority to accept spent nuclear fuel under Atomic Energy Act authority except in compelling circumstances, such as an emergency involving spent nuclear fuel threatening public health.

tons of nuclear waste until the repository started accepting spent nuclear fuel. Therefore, unless provisions in NWPA were amended, centralized storage would have to be funded, owned, and operated privately. A privately operated centralized storage facility alternative, such as the proposed Private Fuel Storage Facility in Utah, would not likely resolve DOE's liabilities with the nuclear power companies.[25]

A second, equally important, challenge to centralized storage is the likelihood of opposition during site selection for a facility. Experts noted that affected states and communities would raise concerns about safety, security, and the likelihood that an interim centralized storage facility could become a de facto permanent storage site if progress is not being made on a permanent repository. Even if a local community supports a centralized storage facility, the state may not. For example, the Private Fuel Storage facility was generally supported by the Skull Valley Band of the Goshute Indians, on whose reservation the facility was to be located, but the state of Utah and some tribal members opposed its licensing and construction. Other states have indicated their opposition to involuntarily hosting a centralized facility through means such as the Western Governors' Association, which issued a resolution stating that "no such facility, whether publicly or privately owned, shall be located within the geographic boundaries of a Western state without the written consent of the governor."[26] Some experts noted that a state or community may be willing to serve as a host if substantial economic incentives were offered and if the party building the site undertook a time-consuming and expensive process of site characterization and safety assessment. However, DOE officials stated that in their previous experience—such as with the Nuclear Waste Negotiator about 15 to 20 years ago—they have found no incentive package that has successfully encouraged a state to voluntarily host a site.

A third challenge to centralized storage is that nuclear waste would likely have to be transported twice—once to the centralized site and once to a permanent repository—if a centralized site were not colocated with a

[25]In addition, lawsuits filed against the government by nuclear reactor owners have included claims to recover the cost of the Private Fuel Storage facility. At least one utility has recovered these costs from the government, while a court did not allow another utility to recover these costs.

[26]Western Governors' Association Policy Resolution 09-5: Interim Storage and Transportation of Commercial Spent Nuclear Fuel.

repository.[27] Therefore, the total distance over which nuclear waste is transported is likely to be greater than with other alternatives, an important factor because, according to one expert, transportation risk is directly tied to this distance. However, according to DOE, nuclear waste has been safely transported in the United States since the 1960s and National Academy of Sciences, NRC, and DOE-sponsored reports have found that the associated risks are well understood and generally low. Yet, there are also perceived risks associated with nuclear waste transportation that can result in lower property values along transportation routes, reductions in tourism, and increased anxiety that create community opposition to nuclear waste transportation. According to experts, transportation risks could be mitigated through such means as shipping the least radioactive fuel first, using trains that only transport nuclear waste, and identifying routes that minimize possible impacts on highly populated areas. In addition, the hazards associated with transportation from a centralized facility to a repository would decline as the waste decayed and became less radioactive at the centralized facility.

Cost Ranges for Centralized Storage Will Vary Depending on Waste Volume and Final Disposition

As shown in table 4, our models generated cost ranges from $23 billion to $81 billion for the centralized storage of 153,000 metric tons of spent nuclear fuel and high-level waste for 100 years followed by geologic disposal. For centralized storage without disposal, costs would range from $12 billion to $20 billion for 70,000 metric tons of waste and from $15 billion to $29 billion for 153,000 metric tons of waste. These centralized model scenarios include the cost of on-site operations required to package and prepare the waste for transportation, such as storing the waste in dry-cask storage until it is transported off site, developing and operating a system to transport the waste to centralized storage, and constructing and operating two centralized storage facilities. (See app. IV for information about our modeling methodology, assumptions, and results.)

[27]NWPA prohibits development of a centralized storage facility in any state where a site is being characterized for development of a repository.

Table 4: Estimated Cost Range for Each Centralized Storage Scenario

Dollars in billions

Centralized storage scenario	Time period covered[a]	2009 present value estimate range
Storage of 70,000 metric tons	2009 to 2108 (100 years)	\$12 to \$20
Storage of 153,000 metric tons	2009 to 2108 (100 years)	\$15 to \$29
Storage of 153,000 metric tons, with disposal in a permanent repository after 100 years	2009 to 2240 (232 years[b])	\$23 to \$81

Source: GAO analysis of data provided by nuclear waste management experts and DOE.

[a]See appendix IV for an explanation of the periods covered by the scenarios.

[b]This period was chosen to capture costs of the hypothetical geologic repository through closure.

Actual centralized storage costs may be more or less than these cost ranges if a different centralized storage scenario is implemented. For example, our models assume that there would be two centralized facilities, but licensing, construction, and operations and maintenance costs would be greater if there were more than two facilities and lower if there was only one facility. Some experts told us that centralized storage would likely be implemented with only one facility because it would be too difficult to site two. But other experts noted that having more sites could reduce the number of miles traveled by the waste and provide a greater degree of geographic equity. The length of time the nuclear waste is stored could also impact the cost ranges, particularly if the nuclear waste were stored for less than or more than the time period assumed in our model. For periods longer than 100 years, experts told us that the dry storage cask systems may be subject to degradation and require repackaging, substantially raising the costs, as well as the level of uncertainty in those costs. Transportation is another area where costs could vary if, for example, transportation was not by rail or if the transportation system differed significantly from what is assumed in our models.

Furthermore, costs could be outside our ranges if the final disposition of the waste is different. Our scenario that includes geologic disposal is based on the current cost projections for Yucca Mountain, but these costs could be significantly different for another repository site or if much of the nuclear waste is reprocessed. A different geologic repository would have unique site characterization costs, may use an entirely different design than Yucca Mountain, and may be more or less difficult to build. Also, reprocessing could contribute significantly to the cost of an alternative.

For example, we previously reported that construction of a reprocessing plant with an annual production throughput of 3,000 metric tons of spent nuclear fuel could cost about $44 billion.[28] Studies analyzed by the Congressional Budget Office estimate that once a reprocessing plant is constructed, spent nuclear fuel could be reprocessed at between $610,000 and $1.4 million per-metric-ton, when adjusted to 2009 constant dollars.[29] This would result in an annual cost of about $2 billion to $4 billion, assuming a throughput of 3,000 metric tons per year.

Finally, the actual cost of implementing one of our centralized storage scenarios would likely be higher than our estimated ranges indicate because our models omit several location-specific costs. These costs could not be quantified in our generic models because we did not make an assumption about the specific location of the centralized facilities. For example, a few experts noted that incentives may be given a state or locality as a basis for allowing a centralized facility to be built, but the incentive amount may vary from location to location based on what agreement is reached. Also, several experts said that rail construction may be required for some locations, which could add significant cost depending on the distance of new rail line required at a specific location. Experts could not provide data for these location-dependent costs to any degree of certainty, so we did not use them in our models. Also, the funding source for government-run centralized storage is unclear. The Nuclear Waste Fund, which electric power companies pay into, was established by NWPA to fund a permanent repository and cannot be used to pay for centralized storage without amending the act. Without such a change, the cost for the federal government to implement this alternative would likely have to be borne by the taxpayers.

[28] GAO, *Global Nuclear Energy Partnership: DOE Should Reassess Its Approach to Designing and Building Spent Nuclear Fuel Recycling Facilities,* GAO-08-483 (Washington, D.C.: April 2008).

[29] The studies used in the Congressional Budget Office's analysis were: Boston Consulting Group, *Economic Assessment of Used Nuclear Fuel Management in the United States* (study prepared for AREVA Inc., July 2006); and Matthew Bunn and others, *The Economics of Reprocessing vs. Direct Disposal of Spent Nuclear Fuel,* Belfer Center for Science and International Affairs, John F. Kennedy School of Government, Harvard University, (Cambridge, Massachusetts, December 2003).

On-Site Storage Would Provide an Intermediate Option with Minimal Effort but Poses Challenges that Could Increase Over Time

On-site storage of nuclear waste provides an intermediate option to manage the waste until the government can take possession of it, requiring minimal effort to change from what the nation is currently doing to manage its waste. In the meantime, other longer term policies and strategies could be considered. Such strategies would eventually be required because the on-site storage alternative would not eliminate the need for final disposal of the waste. Some experts believe that legal, community, and technical challenges associated with on-site storage will intensify as the waste remains on site without plans for final disposition because, for example, communities are more likely to oppose recertification of on-site storage. The estimated cost to continue storing 153,000 metric tons of nuclear waste on site for 100 years range from $13 billion to $34 billion, and total costs would range from $20 billion to $97 billion if the nuclear waste is stored on site for 100 years and then disposed in a geologic repository.

On-Site Storage Would Require Minimal Near-Term Logistics and Provide Time to Decide on Long-Term Waste Management Strategies

Because of delays in the Yucca Mountain repository, on-site storage has continued as the nation's strategy for managing nuclear waste, thus its continuation would require minimal near-term effort and allow time for the nation to consider alternative long-term nuclear waste management options. This alternative maintains the waste in a configuration where it is readily retrievable for reprocessing or other disposition, according to an expert. However, like centralized storage, on-site storage is an interim strategy that relies on active institutional controls, such as monitoring, maintenance, and security. To permanently isolate the waste from humans and the environment without the need for active institutional controls some form of final disposal would be required, even if some of the waste were reprocessed.

The additional time in on-site storage may also make the waste safer to handle because older spent nuclear fuel and high-level waste has had a chance to cool and become less radioactive. As a result, on-site storage could reduce transportation risks, particularly in the near-term, since the nuclear waste would be cooler and less radioactive when it is finally transported to a repository. In addition, some experts state that older, cooler waste may provide more predictability in repository performance and be some degree safer than younger, hotter waste. However, NRC cautioned that the ability to handle the waste more safely in the future also depends on other factors, including how the waste or waste packages might degrade over time. In particular, NRC stated that there are many uncertainties with the behavior of spent nuclear fuel as it ages, such as potential fracturing of the structural assemblies, possibly increasing the

risks of release. If the waste has to be repackaged, for example, the process may require additional safety measures. Some experts noted that continuing to store nuclear waste on site would be more equitable than consolidating it in one or a few areas. As a result, the waste, along with its associated risks, would be kept in the location where the electrical power was generated, leaving the responsibility and risks of the waste in the communities that benefited from its generation.

On-Site Storage Poses Legal, Community, and Technical Challenges that Are Likely to Intensify over Time

With on-site storage of DOE-managed spent nuclear fuel and high-level waste, DOE would have difficulty meeting enforceable agreements with states, which could result in significant costs being incurred the longer spent nuclear fuel remains on site. In addition to Idaho's agreement to impose a penalty of $60,000 per day if spent nuclear fuel is not removed from the state by 2035, DOE has an agreement with Colorado stating that if the spent fuel at Fort St. Vrain is not removed by January 1, 2035, the government will, subject to certain conditions, pay the state $15,000 per day until it is removed. Other states where DOE spent nuclear fuel and high-level waste are currently stored may seek similar penalties if the spent fuel and waste remain on-site with no progress toward a permanent repository or centralized storage facility.

A second challenge is the cost due to the government's possible legal liabilities to commercial reactor operators. Leaving waste on site under the responsibility of the electric power companies does not relieve the government of its obligation to take custody of the waste, thus the liability debt could continue to mount. For every year after 2020 that DOE fails to take custody of the waste in accordance with its contracts with the reactor operators, DOE estimates that the government will continue to accumulate up to $500 million per year beyond the estimated $12 billion in liabilities that will have accrued up to that point; however, the outcome of pending litigation could substantially affect the government's total liability.[30] The government will no longer incur these costs if DOE takes custody of the waste. Some representatives from industry have stated that it is not practical for DOE to take custody of the waste at commercial reactor sites. Moreover, some electric power company executives have stated that their ratepayers are paying for DOE to provide a geologic repository through

[30]Legislative action by the Congress could also affect the amount of compensation the government ultimately pays to the reactor operators. For example, the Congress could amend NWPA to change contract provisions that would be applicable to newly constructed reactors.

their contributions to the Nuclear Waste Fund, and the executives believe that simply taking custody of the waste is not sufficient. A DOE official stated that if DOE were to take custody of the waste on site, it would be a complex undertaking due to considerations such as liability for accidents.

Third, continued use of on-site storage would likely also face community opposition. Some experts noted that without progress on a centralized storage facility or repository site to which waste will be moved, some state and local opposition to reactor storage site recertification will increase, and so will challenges to nuclear power companies' applications for reactor license extensions and combined licenses to construct and operate new reactors. Also, experts noted that many commercial reactor sites are not suitable for long-term storage, and none has had an environmental review to assess the impacts of storing nuclear waste at the site beyond the period for which it is currently licensed. One expert noted that if on-site storage were to become a waste management policy, the long-term health, safety, and environmental risks at each site would have to be evaluated. Because waste storage would extend beyond the life of nuclear power reactors, decommissioned reactor sites would not be available for other purposes, and the former reactor operators may have to stay in business for the sole purpose of storing nuclear waste.

Finally, although dry cask storage is considered reliable in the short term, the longer-term costs, maintenance requirements, and security requirements are not well understood. Many experts said waste packages will likely retain their integrity for at least 100 years, but eventually dry storage systems may begin to degrade and the waste in those systems would have to be repackaged. However, commercial dry storage systems have only been in existence since 1986, so nuclear utilities have little experience with long-term system degradation and requirements for repackaging. Some experts suggested that only the outer protective cask would require replacement, but the inner canister would not have to be replaced. Yet, other experts said that, over time, the inner canister would also be exposed to environmental conditions by vents in the outer cask, which could cause corrosion and require a total system replacement. In addition, experts disagreed on the relative safety risks and costs associated with using spent fuel pools to transfer the waste during repackaging compared to using a dry transfer system, which industry representatives said had not been used on a commercial scale. Finally, future security requirements for extended storage are uncertain because as spent nuclear waste ages and becomes cooler and less radioactive, it becomes less lethal to anyone attempting to handle it without protective shielding. For example, a spent nuclear fuel assembly can lose nearly 80

percent of its heat 5 years after it has been removed from a reactor, thereby reducing one of the inherent deterrents to thieves and terrorists attempting to steal or sabotage the spent nuclear fuel and potentially creating a need for costly new security measures.

Cost Ranges for On-Site Storage Will Vary Depending on Waste Volume, Final Disposition, and Duration of Storage

As shown in table 5, our models generated cost ranges from $20 billion to $97 billion for the on-site storage of 153,000 metric tons of spent nuclear fuel and high-level waste for 100 years followed by geologic disposal. For only on-site storage for 100 years without disposal, costs would range from $10 billion to $26 billion for 70,000 metric tons of waste and from $13 billion to $34 billion for 153,000 metric tons of waste. On-site storage costs would increase significantly if the waste were stored for longer periods—storing 153,000 metric tons on site for 500 years would cost from $34 billion to $225 billion—because it would have to be repackaged every 100 years for safety. The on-site storage model scenarios include the costs of on-site operations required to package the waste into dry canister storage, build additional dry storage at the reactor sites, prepare the waste for transportation, and operate and maintain the on-site storage facilities. Most of the costs for the first 100 years would result from the initial loading of materials into dry storage systems. (See app. IV for information on our modeling methodology, assumptions, and results.)

Table 5: Estimated Cost Range for Each On-site Storage Scenario

Dollars in billions

On-site storage scenario	Period covered[a]	2009 present value estimate range
Storage of 70,000 metric tons	2009 to 2108 (100 years)	$10 to $26
Storage of 153,000 metric tons	2009 to 2108 (100 years)	$13 to $34
Storage of 153,000 metric tons, with disposal in a permanent repository after 100 years	2009 to 2240 (232 years[b])	$20 to $97
Storage of 153,000 metric tons with repackaging every 100 years	2009 to 2508 (500 years)	$34 to $225

Source: GAO analysis of data provided by nuclear waste management experts and DOE.

[a]See appendix IV for an explanation of the periods covered by the scenarios.

[b]This period was chosen to capture costs of the hypothetical geologic repository through closure.

Actual on-site storage costs may be more or less than these cost ranges if a different on-site storage scenario is implemented. For example, to keep it distinct from the centralized storage models, our on-site storage models

assume that there would be no transportation or consolidation of waste between the reactor sites. However, several experts noted that in an actual on-site storage scenario, reactor operators would likely consolidate their waste to make operations more efficient and reduce costs. Also, as with the centralized storage alternative, costs for the on-site storage scenario that includes geologic disposal could differ for a repository site other than Yucca Mountain or for additional waste management technologies.

Finally, our models did not include certain costs that were either location-specific or could not be predicted sufficiently to be quantified for our purposes, which would make the actual costs of on-site storage higher than our cost ranges. For example, the taxes and fees associated with on-site storage could vary significantly by state and over time. Also, repackaging operations in our 500-year on-site storage scenario would generate low-level waste that would require disposal. However, the amount of waste generated and the associated disposal costs could vary depending on the techniques used for repackaging. Finally, the total amount of the government's liability for failure to begin taking spent nuclear fuel for disposal in 1998 will depend on the outcome of pending and future litigation.

Like the centralized storage alternative, the funding source for the on-site storage alternative is uncertain. Currently, the reactor operators have been paying for the cost to store the waste, but have filed lawsuits to be compensated for storage costs of waste that the federal government was required to take title to under standard contracts. Payments resulting from these lawsuits have come from the Department of the Treasury's judgment fund, which is funded by the taxpayer, because a court determined that the Nuclear Waste Fund could not be used to compensate electric power companies for their storage costs. Without legislative or contractual changes—such as allowing the Nuclear Waste Fund to be used for on-site storage—taxpayers would likely bear the ultimate costs for on-site storage.

Concluding Observations

Developing a long-term national strategy for safely and securely managing the nation's high-level nuclear waste is a complex undertaking that must balance health, social, environmental, security, and financial factors. In addition, virtually any strategy considered will face many political, legal, and regulatory challenges in its implementation. Any strategy selected will need to have geologic disposal as a final disposition pathway. In the case of the Yucca Mountain repository, these challenges have left the nation with nearly three decades of experience. In moving forward, whether the

nation commits to the same or a different waste management strategy, federal agencies, industry, and policy makers at all levels of government can benefit from the lessons of Yucca Mountain. In particular, stakeholders can better understand the need for a sustainable national focus and community commitment. Federal agencies, industry, and policymakers may also want to consider a strategy of complementary and parallel interim and long-term disposal options—similar to those being pursued by some other nations—which might provide the federal government with maximum flexibility, since it would allow time to work with local communities and to pursue research and development efforts in key areas, such as reprocessing.

Agency Comments

We provided DOE and NRC with a draft of this report for their review and comment. In their written comments, DOE and NRC generally agreed with the report. (See apps. V and VI.) In addition, both DOE and NRC provided comments to improve the draft report's technical accuracy, which we have incorporated as appropriate.

We also discussed the draft report with representatives of the Nuclear Waste Technical Review Board, the Nuclear Energy Institute, and the State of Nevada Agency for Nuclear Projects. These representatives provided comments to clarify information in the draft report, which we have incorporated as appropriate.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies of this report to other appropriate congressional committees, the Secretary of Energy, the Chairman of NRC, the Director of the Office of Management and Budget, and other interested parties. The report also will be available at no charge on the GAO Web site at http://www.gao.gov.

If you or your staffs have any questions about this report, please contact me at (202) 512-3841 or gaffiganm@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs can be found on the last page of this report. GAO staff who made major contributions to this report are listed in appendix VII.

Mark E. Gaffigan
Director, Natural Resources
and Environment

Appendix I: Scope and Methodology

For this report we examined (1) the key attributes, challenges, and costs of the Yucca Mountain repository; (2) alternative nuclear waste management approaches; (3) the key attributes, challenges, and costs of storing the nuclear waste at two centralized sites; and (4) the key attributes, challenges, and costs of continuing to store the nuclear waste at its current locations.

Developing Information on Key Attributes, Challenges, and Costs of Yucca Mountain

To provide information on the key attributes and challenges of the Yucca Mountain repository, we reviewed documents and interviewed officials from the Department of Energy's (DOE) Office of Civilian Radioactive Waste Management and Office of Environmental Management; the Nuclear Regulatory Commission's (NRC) Division of Spent Fuel Storage and Transportation and Division of High Level Waste Repository Safety, both within the Office of Nuclear Material Safety and Safeguards; and the Department of Justice's Civil Division. We also reviewed documents and interviewed representatives from the National Academy of Sciences, the Nuclear Waste Technical Review Board, and other concerned groups. Once we developed our preliminary analysis of Yucca Mountain's key attributes and challenges, we solicited input from nuclear waste management experts. (See app. II for our methodology for soliciting comments from nuclear waste management experts and app. III for a list of these experts.)

To analyze the costs for the Yucca Mountain repository through to closure, we started with the cost information in DOE's Yucca Mountain Total System Lifecycle Cost report, which used 122,100 metric tons of nuclear waste in its analysis.[1] We asked DOE officials to provide a breakdown of the component costs on a per-metric-ton basis that DOE used in the Total System Lifecycle Cost report. We used this information to calculate the costs of a repository at Yucca Mountain for 70,000 metric tons and 153,000 metric tons, changing certain component costs based on the ratio between 70,000 and 122,100 or 153,000 and 122,100. For example, we modified the cost of constructing the tunnels for emplacing the waste for the 70,000-metric-ton scenario by 0.57, the ratio of 70,000 metric tons to 122,100 metric tons. We applied this approach to component costs that would be

[1]DOE, *Analysis of the Total System Lifecycle Cost of the Civilian Radioactive Waste Management Program, Fiscal Year 2007*, DOE/RW-0591 (Washington, D.C., July 2008). The 122,100 metric tons of nuclear waste included the spent nuclear fuel expected to be generated from all commercial nuclear reactors that had received NRC license extensions through January 2007.

impacted by the ratio difference, particularly for transporting and emplacing the waste and installing drip shields. We also incorporated DOE's cost estimates for potential delays to licensing the Yucca Mountain repository into our analysis and made modifications to the analysis based on comments by cognizant DOE officials. Finally, we discounted DOE's costs, which were in 2008 constant dollars, to 2009 present value using the methodology described in appendix IV.

Examining and Identifying Nuclear Waste Management Alternatives

To examine and identify alternatives, we started with a series of interviews among federal and state officials and industry representatives. We also gathered and reviewed numerous studies and reports on managing nuclear waste— along with interviewing the authors of many of these studies— from federal agencies, the National Academy of Sciences, the Nuclear Waste Technical Review Board, the Massachusetts Institute of Technology, the American Physical Society, Harvard University, the Boston Consulting Group, and the Electric Power Research Institute. To better understand how commercial spent nuclear fuel is stored, we visited the Dresden Nuclear Power Plant in Illinois and the Hope Creek Nuclear Power Plant in New Jersey, which both store spent nuclear fuel in pools and in dry cask storage. We also visited DOE's Savannah River Site in South Carolina and Fort St. Vrain site in Colorado to observe how DOE-managed spent nuclear fuel and high-level waste are processed and stored.

As we began to identify potential alternatives to analyze, we shared our initial approach and methodology with nuclear waste management experts—including members of the National Academy of Sciences and the Nuclear Waste Technical Review Board to obtain their feedback—and revised our approach accordingly. Many of these experts advised us to develop generic, hypothetical alternatives with clearly defined assumptions about technology and environmental conditions. Industry representatives and other experts advised us that trying to account for the thousands of variables relating to geography, the environment, regional regulatory differences, or differences in business models would result in infeasible and unmanageable models. They also advised us against trying to predict changes in the future for technologies or environmental conditions because they would purely conjectural and fall beyond the scope of this analysis.

Based on this information, we identified two generic, hypothetical alternatives to use as the basis of our analysis: centralized storage and on-site storage. Within each of these alternatives, we identified different scenarios that examined the costs associated with the management of

70,000 metric tons and 153,000 metric tons of nuclear waste and whether or not the waste is shipped to a repository for disposal after 100 years.

Once we identified the alternatives, we again consulted with experts to establish assumptions regarding commercial spent nuclear fuel management and its associated components to define the scope and specific processes that would be included in each alternative. To identify a more complete, qualified list of nuclear waste management experts with relevant experience who could provide and critique this information, we used a technique known as snowballing. We started with experts in the field who were known to us, primarily from DOE, NRC, National Council of State Legislators, the State of Nevada Agency for Nuclear Projects, the Nuclear Energy Institute, and the National Association of Regulatory Utility Commissioners and asked them to refer us to other experts, focusing on U.S.-based experts. We then contacted these individuals and asked for additional referrals. We continued this iterative process until additional interviews did not lead us to any new names or we determined that the qualified experts in a given technical area had been exhausted.

We conducted an initial interview with each of these experts by asking them questions about the nature and extent of their expertise and their views on the Yucca Mountain repository. Specifically, we asked each expert:

- What is the nature of your expertise? How many years have you been doing work in this area? Does your expertise allow you to comment on planning assumptions and costs of waste management related to storage, disposal, or transport?
- If you were to classify yourself in relation to the Yucca Mountain repository, would you classify yourself as a proponent, an opponent, an independent, an undecided or uncommitted, or some combination of these?

We then narrowed our list down to those individuals who identified themselves or whom others identified as having current, nationally recognized expertise in areas of nuclear waste management that were relevant to our analysis. For balance, we ensured that we included experts who reflected (1) key technical areas of waste management; (2) a range of industry, government, academia, and concerned groups; and (3) a variety of viewpoints on the Yucca Mountain repository. (See app. III for 147 experts we contacted.)

Once we developed our list of experts, we classified them into three groups:

- Those whose expertise would allow them to provide us with specific information and advice on the processes that should be included in each alternative and the best estimates of expected cost ranges for the components of each alternative, such as a typical or reasonable price for a dry cask storage.
- Those who could weigh in on these estimates, as well as give us insight and comments on assumptions that we planned to use to define our alternatives.
- Those whose expertise was not in areas of component costs, but who could nonetheless give us valuable information on other assumptions, such as transportation logistics.

To define our alternatives and develop the assumptions and cost components we needed for our analysis, we started with the experts from the first group who had the most direct and reliable knowledge of the processes and costs associated with the alternatives we identified. This group consisted of seven experts and included federal government officials and representatives from industry. We worked closely with these experts to identify the key assumptions that would establish the scope of our alternatives, the more specific assumptions to identify the processes associated with each alternative, the components of these processes that we could quantify in terms of cost, and the level of uncertainty associated with each component cost. For example, two of the experts in this first group told us that for the on-site alternative, commercial reactor sites that did not already have independent spent nuclear fuel storage installations would have to build them during the next 10 years and that the cost for licensing, design, and construction of each installation would range from $24 million to $36 million. Once we had gathered our initial assumptions and cost components, we used a data collection instrument to solicit comments on them from all of our experts. We then used the experts' comments to refine our assumptions and component costs. (See app. II for our methodology for consulting with this larger group of nuclear waste management experts.)

DOE officials provided assumptions and cost data for managing DOE spent nuclear fuel and high-level waste, which we incorporated into our analysis of the centralized storage and on-site storage alternatives. These assumptions and cost information covered management of spent nuclear

fuel and high-level waste at DOE's Idaho National Laboratory, Hanford Reservation, Savannah River Site, and West Valley site.

Developing Information on Key Attributes, Challenges, and Costs of the Centralized Storage and On-Site Storage Alternatives

To gather information on the key attributes and challenges of our alternatives, we interviewed agency officials and nuclear waste management experts from industry, academic institutions, and concerned groups. We also reviewed the reports and studies and visited the locations that were mentioned in the previous section. To ensure that the attributes and challenges we developed were accurate, comprehensive, and balanced, we asked our snowballed list of experts to provide their comments on our work, using the data collection instrument that is described in appendix II. We used the comments that we received to expand the attributes or challenges on our list or, where necessary, to modify our characterization of individual attributes or challenges.

To generate cost ranges for the centralized storage and on-site storage alternatives, we developed four large-scale cost models that analyzed the costs for each alternative of storing 70,000 metric tons and 153,000 metric tons of nuclear waste for 100 years followed by disposal in a geologic repository. (See app. IV.) We also generated cost ranges for each alternative of storing the waste for 100 years without including the cost of subsequent disposal in a geologic repository for storing 153,000 metric tons of waste on site for 500 years. For each model, which rely upon data and assumptions provided by nuclear waste management experts, the cost range was based on the annual volume of commercial spent nuclear fuel that became ready to be packaged and stored in each year. In general, each model started in 2009 by annually tracking costs of initial packaging and related costs for the first 100 years and for every 100 years thereafter if the waste was to remain on site and be repackaged. Since our models analyzed only the costs associated with storing commercial nuclear waste management, we augmented them with DOE's cost data for (1) managing its spent nuclear fuel and high-level waste and (2) constructing and operating a permanent repository. Specifically, we used DOE's estimated costs for the Yucca Mountain repository to represent cost for a hypothetical permanent repository.[2]

[2]We excluded historical costs for the Yucca Mountain repository because these costs represent challenges unique to Yucca Mountain and may not be applicable to a future repository. However, the bulk of future cost for construction, operation, and closure may be representative of a new repository.

We conducted this performance audit from April 2008 to October 2009 in accordance with generally accepted government auditing standards. These standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Appendix II: Our Methodology for Obtaining Comments from Nuclear Waste Management Experts

As discussed in appendix I, we gathered the assumptions and associated component costs used to define our nuclear waste management alternatives by consulting with experts in an iterative process of identifying initial assumptions and component costs and revising them based on expert comments. This appendix (1) describes the data collection instrument we used to obtain comments on the initial assumptions and component costs, (2) describes how we analyzed the comments and revised our assumptions, and (3) provides a list of the assumptions and cost data that we derived through this process and used in our cost models.

To obtain comments from a broad group of nuclear waste management experts, we compiled the initial assumptions and component costs that we gathered from a small group of experts into a data collection instrument that included

- a description of the Yucca Mountain repository and our proposed nuclear waste management alternatives—on-site storage and centralized storage—and attributes and challenges associated with them;
- our initial assumptions that would identify and define the processes, time frames, and major components used to bound our hypothetical centralized and on-site storage alternatives;
- the major component costs of each alternative, including definitions and initial cost data; and
- components associated with each alternative with a high degree of uncertainty that we did not attempt to quantify in terms of costs.

The data collection instrument asked the experts to answer specific questions about each piece of information that we provided (see table 6).

Table 6: Our Data Collection Instrument for Nuclear Waste Management Experts

Section of the data collection instrument	Questions asked of the experts
Description of each alternative and its attributes and challenges	What additional issues do you suggest we consider, or is there one listed that you would modify?
List of initial assumptions for each alternative	To what extent to you think this assumption is reasonable or unreasonable?[a] If this assumption does not seem reasonable, please describe.[a] Are there additional assumptions defining our scenario not mentioned above that you would recommend GAO consider? Please describe.
List of component costs and initial cost data	Is this estimate reasonable or unreasonable?[a] If this estimate is not reasonable, please describe why (estimate too high, estimate too low, range too broad, range too narrow) and, if possible, provide specific alternative cost estimates.[a] Please tell us anything about this cost item that might make it difficult (or not difficult) to estimate accurately?[a] Are there additional cost categories not mentioned above that you would recommend GAO consider? Please provide a generic cost estimate or potential source of such an estimate, if possible.
List of uncertain components	In your opinion, do you think any of these items can be quantified? If so, please provide suggestions for how to quantify them, along with supporting data, if available.

Source: GAO.

[a]This question was asked after each assumption or component.

We pretested our instrument with several individual experts to ensure that our questions were clear and would provide us with the information that we needed, and then refined the instrument accordingly. Next, we sent the instrument to 114 experts who were identified through our snowballing methodology (see apps. I and III). Each expert received the sections of our data collection instrument that included the attributes and challenges of the alternatives and the initial assumptions, but only those experts with the type and level of expertise to comment on costs received the cost component sections.

We received 67 sets of comments from independent experts and experts representing industry, federal government, state governments, and other concerned groups.[1] These experts also represented a range of viewpoints on the Yucca Mountain repository. Each of their responses was compiled

[1]The 67 sets of comments do not reflect the total number of experts who responded because some groups of affiliated experts compiled their comments into a single response. For example, DOE's Office of Civilian Radioactive Waste Management provided a consolidated set of comments for its nine experts.

into a database organized by each individual assumption or cost element for the on-site storage and centralized interim storage alternatives.

To arrive at the final assumptions and cost component data for our models, we qualitatively analyzed the experts' comments. The comments we received on the assumptions differed in nature from those we received on the component costs, so our analysis and disposition of comments differed slightly. For the assumptions, we took the comments on each assumption that were made when an expert did not believe it was entirely reasonable and grouped comments that were similar. We determined the relevance of a comment to our assumption based on whether the comment provided a basis upon which we could modify the assumption or was within the scope or capability of our models. For example, we received several comments about how an assumption may be affected by nuclear waste from new reactors, including potential liabilities if the Department of Energy (DOE) does not take custody of that waste, but in the key assumptions defining our alternatives, we explicitly excluded new reactors because we could not predict how many new reactors would be built, when they would operate, and the amount of waste that they would generate. For those comments that were relevant, we weighed the expertise of those making the comments and determined whether the balance of the comments warranted a modification to our preliminary assumption. In some instances, we conducted followup interviews with selected experts to clarify issues that the broad group of experts raised.

For the component costs, we organized the comments on a particular component based on whether an expert thought the cost and uncertainty range was reasonable, too high, too low, the range was too broad, or the range was too narrow. We developed a ranking system to identify which experts had the greatest degree of direct experience or knowledge with the cost and weighed their comments accordingly to determine whether our preliminary cost should be modified. Also, we took into account the incidence of expert agreement or disagreement when deciding how much uncertainty to apply to a particular cost.

Through this analysis, we determined that the preponderance of our preliminary assumptions and cost data were reasonable for use in our models either because the experts generally agreed it was reasonable, or the experts who thought it was reasonable had a greater degree of relevant expertise or knowledge than those who commented otherwise. However, some of the experts' responses indicated that a modification to our model was needed. Table 7 presents a summary of the modifications we made to

our model assumptions and cost data based on the expert comments received.

Table 7: Initial Assumptions and Component Cost Estimates for Our Centralized Storage and On-site Storage Alternatives and Modifications Made Based on Experts' Responses to Our Data Collection Instrument

Centralized storage		
Key aspect of the alternative	**Initial key assumption**	**Modification based on expert comments**
Number of sites	Two sites located in different geographic regions of the country.	None
Reactor operations	Current reactors will receive, if they have not already, a 20-year license extension and will operate until the end of their licensed life.	None
	When reactors cease operations, they will be decommissioned and only spent nuclear fuel dry storage will remain on site.	None
Transportation	Transportation will be the similar to what is assumed for the Yucca Mountain repository—via rail, using dedicated trains.	None
Repackaging	Waste will not be repackaged at the centralized facilities.[a]	None
Final disposition	Waste will be stored at the centralized sites until 100 years from now and then be disposed of in a geologic repository.[b]	None
Process	**Initial process assumption**	**Modification based on expert comments**
Waste packaged into dry storage casks	Reactor operators will only move the amount of waste from pools into dry storage that is necessary to preserve full-core offload capability—the capacity in their spent nuclear fuel pools to store all of the fuel in the reactor core.	None
	The overall amount of fuel moved from the pools to dry storage will be equal to estimated annual rates at which fuel is discharged from the reactors.	None
	Dual-purpose canister systems will be used until Transportation, Aging and Disposal systems become widely available.	Only dual-purpose systems will be used.
	Transportation, Aging and Disposal systems will have a capacity of 8.5 metric tons plus or minus 5 percent.	None (although this assumption became obsolete when we no longer assumed transportation, aging, and disposal systems would be used).

Centralized storage		
Reactor site dry storage	All reactor sites without dry storage facilities will construct them at the time they lose full-core offload capability—the capacity in their spent nuclear fuel pools to store all of the fuel in the reactor core.	None
	Dry storage operations and maintenance costs vary by nature of the site, such as operating versus decommissioned.	None
	On average, 1.5 decommissioned reactor sites will be cleared of their waste each year.	None
Transportation to centralized storage	Once running at full capacity, transportation rates will be approximately 3,000 metric tons per year (what is assumed for Yucca Mountain).	None
	Waste from decommissioned sites and GE Morris will be transported before waste from operating sites. This waste would not be converted to dry storage prior to transportation.	None
	133 transportation casks will be required (what is assumed for Yucca Mountain) and will be acquired over a 7-year period.	None
	No new rail construction will be required.	None
	Transportation system infrastructure, system support, and operations will be analogous to what DOE assumes for Yucca Mountain.	None
Centralized storage	The two centralized facilities will begin accepting waste in 2028.	None
	The sites will be built at existing federal facilities and be owned and operated by DOE.	None
Geologic disposal	Waste will not be repackaged before being disposed of in a permanent repository.	None
	Any spent nuclear fuel not originally packaged into a Transportation, Aging and Disposal canister will be repackaged at the geologic repository.	This assumption became obsolete when we no longer assumed transportation, aging, and disposal canisters would be used.

Process component	Initial component cost estimate	Modification based on expert comments
Dry cask storage systems: • transportation, aging, and disposal • dual-purpose	• $1.1 million plus or minus 10 percent • $900,000 plus or minus 5 percent	• Obsolete • $900,000 plus or minus 25 percent
Loading operations: • cost per cask to load fuel into dry storage canisters • loading campaign consisting, on average, of five casks (including set-up, clean up, training, and labor)	• $150,000 plus or minus 5 percent • $750,000 plus or minus 5 percent	• $275,000 plus or minus 45 percent • None

Centralized storage		
Design, licensing, and construction of dry storage installations at reactor sites	$30 million plus or minus 20 percent	$30 million plus or minus 40 percent
Annual operations and maintenance: • operating reactor site dry storage • decommissioned reactor site dry storage • decommissioned reactor site wet storage	• $100,000 plus or minus 20 percent • $3 million plus or minus 20 percent • $10 million plus or minus 20 percent	• $100,000 plus or minus 50 percent • $4.5 million plus or minus 40 percent • None
Transportation casks	$4.5 million plus or minus 10 percent	None
Loading for transportation cost per canister	$250,000 plus or minus 5 percent	$150,000 plus or minus 40 percent
Transportation infrastructure: • rolling stock and facilities • transportation system support	• $400 million plus or minus 10 percent • $2.5 billion plus or minus 10 percent	• None • None
Transportation operations per-metric-ton	$26,000 plus or minus 10 percent	None
Centralized facility licensing and construction: • 70,000 metric ton facility • 153,000 metric ton facility	• $168 million plus or minus 10 percent • $232 million plus or minus 10 percent	• $218 million plus or minus 20 percent • $302 million plus or minus 20 percent
Centralized facility annual operations and maintenance	$8.8 million plus or minus 10 percent	None
On-site storage		
Key aspect of the alternative	**Initial key assumption**	**Modification based on expert comments**
Number of commercial sites	Commercial spent nuclear fuel spent nuclear fuel will be stored at 75 reactor sites.	None
Number of DOE sites	DOE high-level waste and spent nuclear fuel will remain at five current sites.	None
Reactor operations	Current reactors will receive, if they have not already, a 20-year license extension and will operate until the end of their licensed life.	None
	When reactors cease operations, they will be decommissioned and only spent nuclear fuel dry storage will remain on site.	None
Transportation	There will be no transportation of waste between sites.	None
Repackaging	Dry cask storage systems would require repackaging every 100 years.	None

On-site storage		
Process	**Initial process assumption**	**Modification based on expert comments**
Waste packaged into dry storage casks	Reactor operators will use generic dual-purpose canisters for dry storage with a capacity of 13 metric tons plus or minus 5 percent.	Range increased to plus or minus 15 percent.
	Reactor operators will only move the amount of waste from pools into dry storage that is necessary to preserve full-core offload capability.	None
	The overall amount of fuel moved from the pools to dry storage will be equal to estimated annual rates at which fuel is discharged from the reactors.	None
Reactor site dry storage	All reactor sites without dry storage facilities will construct them at the time they lose full-core offload capability.	None
	Dry storage operations and maintenance costs vary by nature of the site, such as operating versus decommissioned.	None
Repackaging	Wet transfer facilities will need to be built at each site for every packaging interval (i.e. every 100 years).	We will assume a generic transfer system that could be either wet or dry.
	All sites will need to replace their dry storage pad and infrastructure every 100 years when they repackage.	None
Process component	**Initial component cost estimate**	**Modification based on expert comments**
Dry cask storage system	$900,000 plus or minus 5 percent	$900,000 plus or minus 25 percent
Loading operations: • cost per cask to load fuel into dry storage canisters • loading campaign consisting, on average, of five casks (including set-up, clean up, training, and labor)	• $150,000 plus or minus 5 percent • $750,000 plus or minus 5 percent	• $275,000 plus or minus 45 percent • None
Design, licensing, and construction of dry storage installations at reactor sites	$30 million plus or minus 20 percent	$30 million plus or minus 40 percent
Annual operations and maintenance: • operating reactor site dry storage • decommissioned reactor site dry storage • decommissioned reactor site wet storage	• $100,000 plus or minus 20 percent • $3 million plus or minus 20 percent • $10 million plus or minus 20 percent	• $200,000 plus or minus 50 percent • $4.5 million plus or minus 40 percent • None
Construction of a transfer facility for repackaging	$300 million plus or minus 50 percent (for a wet transfer facility)	$300 million plus or minus 50 percent (for either a wet or a dry transfer facility)

On-site Storage		
Repackaging operations: • repackaging costs per cask • repackaging campaign consisting, on average, of 5 casks (including set-up, clean up, training, and labor)	• $1.2 million plus or minus 10 percent • $750,000 plus or minus 10 percent	• $1.6 million plus or minus 10 percent • None
Storage pad replacement	$30 million plus or minus 20 percent	$30 million plus or minus 40 percent

Source: GAO analysis based on expert-provided data.

Note: Unless specifically noted, all assumptions and costs apply specifically to commercial nuclear power sites. We used information provided by DOE for the assumptions and costs related to DOE-managed spent nuclear fuel and high-level waste.

[a]We did not explicitly solicit comment on this assumption in the data collection instrument for the centralized storage alternative because we solicited comments on the repackaging requirements in the on-site alternative.

[b]This assumption applies only to the version of our centralized storage alternative that includes final disposal.

Appendix III: Nuclear Waste Management Experts We Interviewed

	Name	Affiliation
1	Mark D. Abkowitz	U.S. Nuclear Waste Technical Review Board (member)
2	John Ahearne	Sigma Xi
3	Joonhong Ahn	National Academy of Sciences/Nuclear and Radiation Studies Board
4	David Applegate	U.S. Geological Survey
5	Wm. Howard Arnold	U.S. Nuclear Waste Technical Review Board (member)
6	Tom Baillieul	The Chamberlain Group
7	James David Ballard	California State University, Northridge
8	William D. Barnard	U.S. Nuclear Waste Technical Review Board (retired) (staff)
9	Lake Barrett	DOE/Office of Civilian Radioactive Waste Management (retired)
10	Barbara Beller	DOE/Office of Environmental Management
11	David W. Bland	TriVis Incorporated
12	Ted Borst	CH2M-WG Idaho, LLC
13	David C. Boyd	Minnesota Public Utilities Commission
14	Michele Boyd	Physicians for Social Responsibility
15	William Boyle	DOE/Office of Civilian Radioactive Waste Management
16	E. William Brach	Nuclear Regulatory Commission (NRC)/Division of Spent Fuel Storage and Transportation
17	Bruce Breslow	State of Nevada Agency for Nuclear Projects
18	Philip Brochman	NRC/Office of Nuclear Security and Incident Response
19	Tom Brookmire	Dominion Resources, Inc.
20	Robert J. Budnitz	Lawrence Berkeley National Laboratory
21	Susan Burke	Idaho Department of Environmental Quality
22	Barbara Byron	Western Interstate Energy Board
23	Robert Capstick	The Yankee Nuclear Power Companies
24	Thure E. Cerling	U.S. Nuclear Waste Technical Review Board (member)
25	Margaret Chu	M.S. Chu & Associates
26	Tom Clements	Friends of the Earth
27	Jean Cline	University of Nevada Las Vegas
28	Thomas Cochran	Natural Resources Defense Council
29	Marshall Cohen	Nuclear Energy Institute
30	Kevin Crowley	Nuclear and Radiation Studies Board, National Research Council of the National Academies
31	Jeanne Davidson	U.S. Department of Justice/Civil Division
32	Bradley Davis	DOE/Office of Nuclear Energy
33	Jack Davis	NRC/Division of High Level Waste Repository Safety
34	Jay C. Davis	Lawrence Livermore National Laboratory (retired) Nuclear and Radiation Studies Board, National Research Council of the National Academies

	Name	Affiliation
35	Scott DeClue	DOE/Office of Environmental Management
36	Edgardo DeLeon	DOE/Office of Environmental Management
37	Fred Dilger	Black Mountain Research
38	David J. Duquette	U.S. Nuclear Waste Technical Review Board (member)
39	Doug Easterling	Wake Forest University
40	Steven Edwards	Progress Energy
41	Randy Elwood	CH2M-WG Idaho, LLC
42	Rod Ewing	University of Michigan
43	Steve Fetter	University of Maryland
44	James Flynn	Pacific World History Institute
45	Charles Forsberg	Massachusetts Institute of Technology
46	Derrick Freeman	Nuclear Energy Institute
47	Steve Frishman	State of Nevada Nuclear Waste Project Office
48	Robert Fronczak	Association of American Railroads
49	B. John Garrick	U.S. Nuclear Waste Technical Review Board (chairman)
50	Ron Gecan	U.S. Congressional Budget Office
51	Lynn Gelhar	Massachusetts Institute of Technology
52	Christine Gelles	DOE/Office of Environmental Management
53	Robert Gisch	Department of Defense/Department of the Navy
54	Aubrey Godwin	Arizona Radiation Regulatory Agency
55	Charles R. Goergen	Washington Savannah River Company[a]
56	Stephen Goldberg	Argonne National Laboratory
57	Steven Grant	Bechtel SAIC Company, LLC[b]
58	Paul Gunter	Beyond Nuclear
59	Brian Gustems	PSEG Nuclear, LLC
60	Brian Gutherman	ACI Nuclear Energy Solutions
61	Roger L. Hagengruber	University of New Mexico Nuclear and Radiation Studies Board, National Research Council of the National Academies
62	R. Scott Hajner	Bechtel SAIC Company, LLC[b]
63	Robert Halstead	Transportation Advisor, State of Nevada Agency for Nuclear Projects
64	Paul Harrington	DOE/Office of Civilian Radioactive Waste Management
65	Ronald Helms	Bechtel SAIC Company, LLC[b]
66	Damon Hindle	Bechtel SAIC Company, LLC[b]
67	James Hollrith	DOE/Office of Civilian Radioactive Waste Management
68	Greg Holden	Department of Defense/Department of the Navy
69	Mark Holt	U.S. Congressional Research Service
70	George M. Hornberger	U.S. Nuclear Waste Technical Review Board (member)

	Name	Affiliation
71	William Hurt	Idaho National Laboratory
72	Thomas H. Isaacs	Stanford University Lawrence Livermore National Laboratory Nuclear and Radiation Studies Board, National Research Council of the National Academies
73	Lisa R. Janairo	Council of State Governments, Midwestern Office
74	Andrew C. Kadak	U.S. Nuclear Waste Technical Review Board (member)
75	Kevin Kamps	Beyond Nuclear
76	Anthony Kluk	DOE/Office of Environmental Management
77	Lawrence Kokajko	NRC/Division of High Level Waste Repository Safety
78	Leonard Konikow	U.S. Geological Survey
79	Christopher Kouts	DOE/Office of Civilian Radioactive Waste Management
80	Steven Kraft	Nuclear Energy Institute
81	Darrell Lacy	Nye County, State of Nevada
82	Gary Lanthrum	DOE/Office of Civilian Radioactive Waste Management
83	Doug Larson	Western Interstate Energy Board
84	Ned Larson	DOE/Office of Civilian Radioactive Waste Management
85	Ronald M. Latanision	U.S. Nuclear Waste Technical Review Board (member)
86	Thomas Leschine	University of Washington
87	Adam H. Levin	Exelon Corporation
88	David Little	Washington Savannah River Company[c]
89	David Lochbaum	Union of Concerned Scientists
90	Bob Loux	Consultant
91	Edwin Lyman	Union of Concerned Scientists
92	Allison Macfarlane	George Mason University
93	Arjun Makhijani	Institute for Energy and Environmental Research
94	Zita Martin	Tennessee Valley Authority
95	Rodney McCullum	Nuclear Energy Institute
96	John McKenzie	Department of Defense/Department of the Navy
97	Richard A. Meserve	Carnegie Institution for Science Nuclear and Radiation Studies Board, National Research Council of the National Academies
98	Barry Miles	Department of Defense/Department of the Navy
99	Thomas Minvielle	Department of Defense/Department of the Navy
100	Bob Mitchell	Yankee Rowe
101	Ali Mosleh	U.S. Nuclear Waste Technical Review Board (member)
102	William M. Murphy	U.S. Nuclear Waste Technical Review Board (member)
103	Connie Nakahara	Utah Department of Environmental Quality
104	Irene Navis	Clark County, Nevada
105	Tara Neider	Transnuclear, Inc.

	Name	Affiliation
106	Brian O'Connell	National Association of Regulatory Utility Commissioners
107	Mary Olson	Nuclear Information and Resource Service
108	Pierre Oneid	Holtec International
109	Ronald S. Osteen	DOE/Office of Environmental Management
110	Jean Ridley	DOE/Office of Environmental Management
111	John Parkyn	Private Fuel Storage
112	Stan Pedersen	Bechtel SAIC Company, LLC[b]
113	Charles W. Pennington	NAC International
114	Mark Peters	Argonne National Laboratory
115	Per Peterson	University of California at Berkeley
116	Henry Petroski	U.S. Nuclear Waste Technical Review Board (member)
117	Max Power	Oregon Hanford Cleanup Board
118	Kenneth Powers	DOE/Office of Civilian Radioactive Waste Management
119	Jay Ray	DOE/Office of Environmental Management
120	Jeffrey Ray	Washington Savannah River Company[c]
121	Everett Redmond II	Nuclear Energy Institute
122	James Robert	Tennessee Valley Authority
123	Gene Rowe	U.S. Nuclear Waste Technical Review Board (staff)
124	Karyn Severson	U.S. Nuclear Waste Technical Review Board (staff)
125	David Shoesmith	University of Western Ontario
126	Linda Sikkema	National Conference of State Legislators
127	Kris Singh	Holtec International
128	Brian M. Smith	Department of Defense/Department of the Navy
129	Susan Smith	DOE/Office of Civilian Radioactive Waste Management
130	Joseph D. Sukaskas	Maine Public Utilities Commission
131	Jane Summerson	DOE/Office of Civilian Radioactive Waste Management
132	Eileen Supko	Energy Resources International, Inc.
133	Bill Swift	Washington Savannah River Company[c]
134	Peter Swift	Sandia National Laboratories
135	Raymond Termini	Exelon Corporation
136	Mike Thorne	Mike Thorne and Associates Limited
137	John Till	Risk Assessment Corporation
138	Richard Tosetti	Bechtel SAIC Company, LLC[b]
139	Brian Wakeman	Dominion Resources, Inc.
140	John Weiss, Jr.	Entergy Corporation
141	Christopher U. Wells	Southern States Energy Board
142	Chris Whipple	ENVIRON International Corporation

	Name	Affiliation
143	James Williams	Western Interstate Energy Board
144	Wayne Worthington	Progress Energy
145	David Zabransky	DOE/Civilian Radioactive Waste Management Board
146	Paul L. Ziemer	Purdue University (retired) Nuclear and Radiation Studies Board, National Research Council of the National Academies
147	Louis Zeller	Blue Ridge Environmental Defense League

Source: GAO.

[a]On August 1, 2008, Savannah River Nuclear Solutions, LLC replaced Washington Savannah River Company as the primary contractor for DOE's Savannah River site. Expert affiliation was with Washington Savannah River Company at the time of our interviews.

[b]On April 1, 2009, USA Repository Services, LLC, replaced Bechtel SAIC Company, LLC, as the primary contractor for the Yucca Mountain repository. Expert affiliation was with Bechtel SAIC Company, LLC at the time of our interviews.

[c]On July 1, 2009, Savannah River Remediation, LLC replaced Washington Savannah River Company as the liquid waste program contractor. Expert affiliation was with Washington Savannah River Company at the time of our interviews.

Appendix IV: Modeling Methodology, Assumptions, and Results

The methodology and results of the models we developed to analyze the total costs of two alternatives for managing nuclear waste are based on cost data and assumptions we gathered from experts. Specifically, this appendix contains information on the following:

- The modeling methodology we developed to generate a range of total costs for the two nuclear waste management alternatives with two different volumes of waste.
- The Monte Carlo simulation process we used to address uncertainties in input data.
- The discounting methodology we developed to derive the present value of total costs in 2009 dollars.
- The individual models and scenarios within each model.
- The results of our cost estimations for each scenario.
- Caveats to our modeling work.

Appendixes I and II describe our methodology for collecting cost data and assumptions and how we ensured their reliability.

Modeling Methodology

The general framework for our models was an Excel spreadsheet that annually tracked all costs associated with packaging, transportation, construction, operation, and maintenance of nuclear waste facilities as well as repackaging of nuclear waste every 100 years when applicable. The starting time period for all models was the year 2009, but the end dates vary depending on the specifics of the scenario. The cost inputs were collected in constant 2008 dollars, but the range of total costs for each scenario was converted to and reported in 2009 present value dollars. Our analysis began with an estimate of existing and future annual volume of nuclear waste ready to be packaged and stored. We chose to model two amounts of waste: 70,000 metric tons and 153,000 metric tons.[1] For ease of

[1]The 70,000 metric tons is the statutory limit placed on the amount of waste that can be disposed of at Yucca Mountain. The 153,000 metric tons is the estimated amount of current waste plus additional commercial spent nuclear fuel that would be generated by 2055 if all currently operating commercial reactors received license extensions.

calculation, we converted all input costs to cost per-metric-ton of waste, when applicable.

The total cost range for each scenario was developed in four steps. First, we developed the total costs for commercial spent nuclear fuel volumes of about 63,000 metric tons and 140,000 metric tons, respectively. Second, we added DOE cost data for its managed waste.[2] Third, we discounted all annual costs to 2009 present value by a discounting methodology discussed later in this appendix. Finally, for scenarios where we assumed that the waste would be moved to a permanent repository after 100 years, we added DOE's cost estimate for the Yucca Mountain repository to represent cost for a permanent repository.[3] To ensure compatibility of cost data that DOE provided with cost ranges generated by our models, we converted DOE cost data to 2009 present value.

Monte Carlo Simulation Process

To address the uncertainties inherent in our analysis, we used a commercially available risk analysis software program called Crystal Ball to incorporate uncertainties associated with the data. This program allowed us to explore a wide range of possible values for all the input costs and assumptions we used to build our models. The Crystal Ball program uses a Monte Carlo simulation process, which repeatedly and randomly selects values for each input to the model from a distribution specified by the user. Using the selected values for cells in the spreadsheet, Crystal Ball then calculates the total cost of the scenario. By repeating the process in thousands of trials, Crystal Ball produces a range of estimated total costs for each scenario as well as the likelihood associated with any specific value in the range.

[2] DOE management costs include spent nuclear fuel managed at the Hanford Reservation, Idaho National Laboratory, and Fort St. Vrain, in Colorado, and high-level waste at the Hanford Reservation, Savannah River Site, Idaho National Laboratory, and West Valley.

[3] We used DOE estimates for Yucca Mountain to represent the cost of a permanent repository. We, however, did not include historical costs for Yucca Mountain as we felt that these historical costs represent challenges unique to Yucca Mountain and may not be applicable to a future repository whereas the bulk of future cost for construction, operation, and closure would be replicated for a new repository.

Discount Rates and Present Value Analysis

One of the inherent difficulties in developing the cost for a nuclear waste disposal option is that costs are spread over thousands of years. The economic concept of discounting is central to such analyses as it allows costs incurred in the distant future to be converted to present equivalent worth. We selected discount rates primarily based on results of studies published in peer reviewed journals. That is, rather than subjectively selecting a single discount rate, we developed our discounting approach based on a methodology and values for discount rates that were recommended by a number of published studies.

We selected studies that addressed issues related to discounting activities whose costs and effects spread across the distant future or many generations, also known as “intergenerational discounting.” In general, we found that these studies were in near consensus on two points: (1) discounting is an appropriate methodology when analyzing projects and policies that span many generations and (2) rates for discounting the distant future should be lower than near term discount rates and/or should decline over time. However, we found no consensus among the studies as to any specific discount rate that should be used. Consequently, we developed a discounting methodology using the following steps:

- We divided the entire time frame of our analysis into five different discounting intervals: immediate, near future, medium future, far future, and far-far future.
- We assumed that within each interval the discount rates were distributed with a triangular distribution.
- Based on all published rates, we developed the maximum, minimum, and mode values for each of the five specified intervals.
- We discounted all costs, using Crystal Ball to randomly and repeatedly select a rate from the appropriate interval and discount cost values using a different rate for each trial.
- Using these steps, we discounted all annual costs to 2009 present value.

Our methodology builds on a wide range of published rates from a number of different sources in concert with the Crystal Ball program. This enabled us, to the extent possible, to address the general lack of consensus on any specific discount rate and, at the same time, address the uncertainties that were inherent in intergenerational discounting and long-term analyses of nuclear waste management alternatives.

Individual Models

We developed the following four models to estimate the cost of several hypothetical nuclear waste disposal alternatives, and we incorporated a number of scenarios within each model to address all uncertainties that we could not easily capture with Crystal Ball:

- **Model I:** Centralized storage for 153,000 metric tons, which included the following scenarios:
  - *Scenario 1:* Centralized storage for 100 years.
  - *Scenario 2:* Centralized storage for 100 years plus a permanent repository after 100 years.
- **Model II:** Centralized storage for 70,000 metric tons, which included one scenario:
  - *Scenario 1:* Centralized storage for 100 years.
- **Model III:** On-site storage using total waste volume of 153,000 metric tons which included the following scenarios:
  - *Scenario 1:* On-site storage for 100 years.
  - *Scenario 2:* On-site storage for 100 years plus a permanent repository after 100 years.
  - *Scenario 3:* On-site storage for 500 years.
- **Model IV:** On-site storage using total waste volume of 70,000 metric tons, which included one scenario:
  - *Scenario 1:* On-site storage for 100 years.

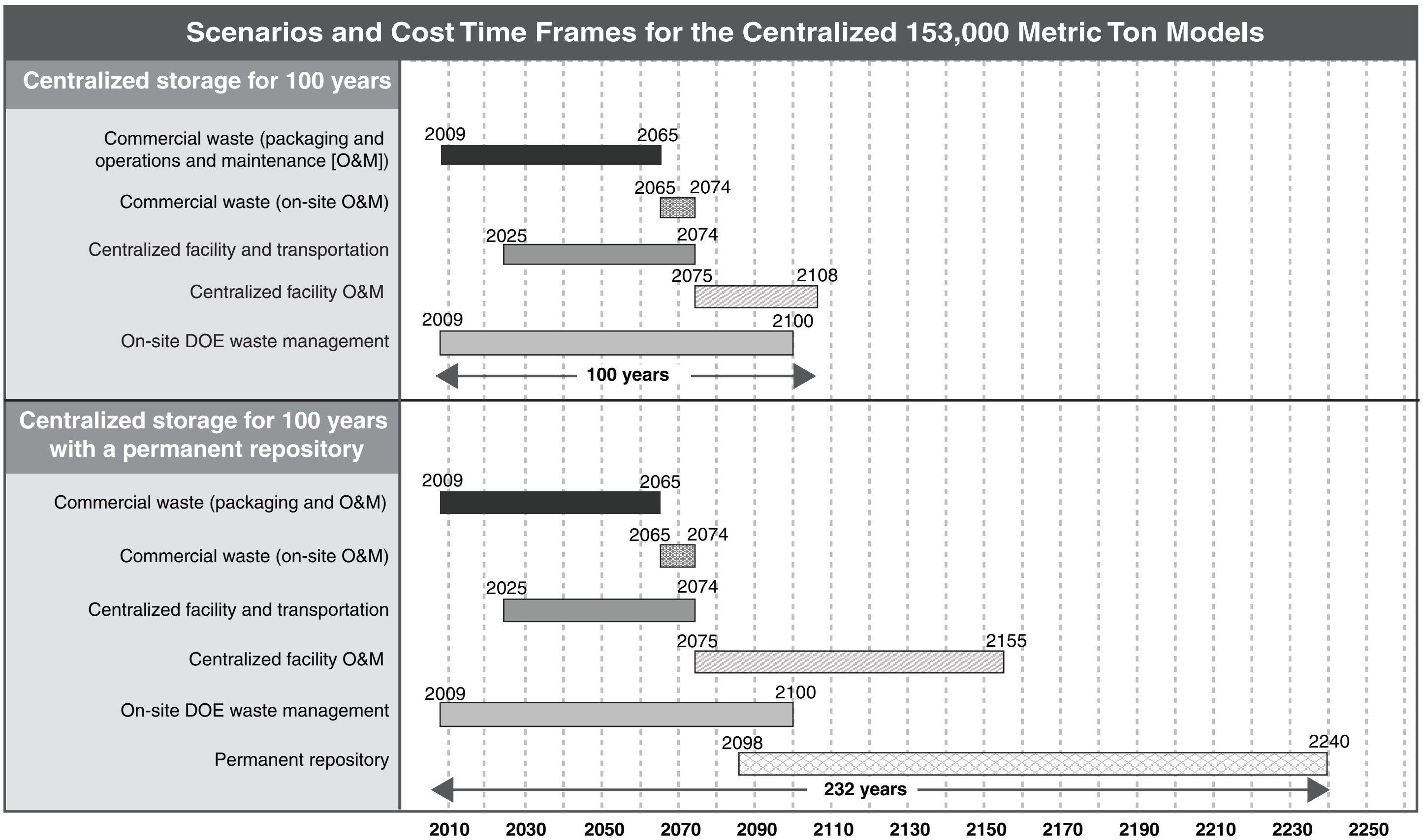
Model I: Centralized Storage (153,000 metric tons)

For this model we assumed that nuclear waste would remain on site until interim facilities are constructed and ready to receive the waste. Two centralized storage facilities would be constructed over 3 years—from 2025 through 2027—and then start accepting waste. The first scenario for this model includes the costs to store waste at the centralized facilities through 2108. In the second scenario, these facilities would stay in

operation through 2155, or 47 years after a permanent repository for the waste would become available. The total analysis period for the cost of this alternative plus permanent repository continues until 2240, when a permanent repository would be expected to close. In general, the costs include the following:

- Initial costs, which include costs of casks, costs for loading of casks, cost of loading campaigns, and operating and maintenance costs by three types of nuclear sites, i.e., operating sites with dry storage, decommissioned sites with dry storage, and decommissioned sites with wet storage. The uncertainty ranges for these costs were from plus or minus 5 percent to plus or minus 50 percent, depending on specific cost variable.
- Costs associated with centralized facilities, including construction costs for centralized facilities, transportation cost for transfer of nuclear waste to centralized facilities, capital and operation and maintenance costs for transportation of waste to centralized facilities and operation and maintenance of centralized facilities. The uncertainty ranges for these costs are from plus or minus 10 percent to plus or minus 40 percent, depending on the cost category.

Figure 6: Scenario and Cost Time Frames for the Centralized 153,000 Metric Ton Models

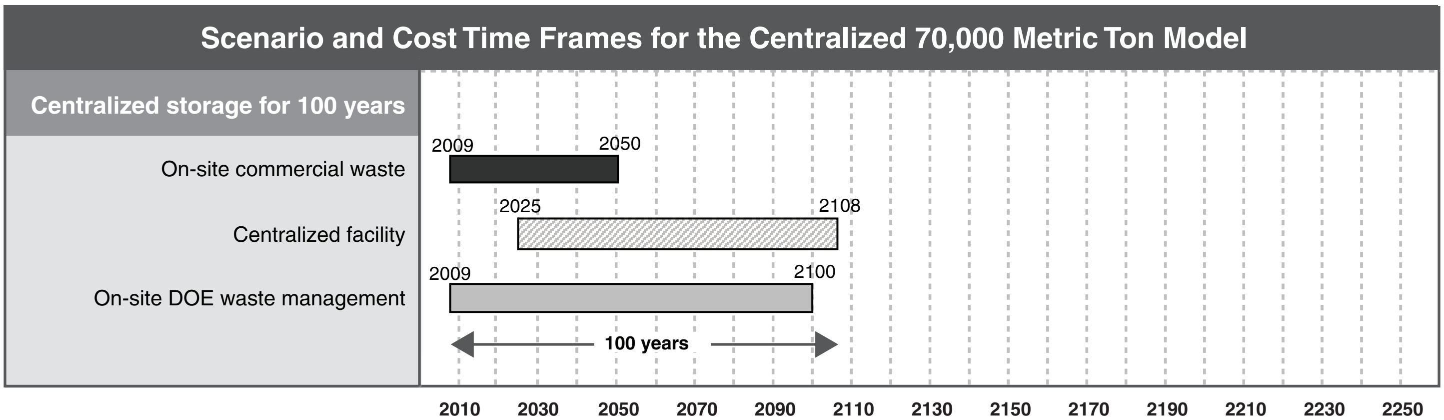


Source: GAO analysis of expert and DOE-provided data.

Model II: Centralized Storage (70,000 metric tons)

This model was developed under the assumption that total existing and newly generated waste from the private sector and DOE will be 70,000 metric tons. The stream of new annual waste ready to be moved to dry storage will continue through 2030. The cost categories and uncertainty ranges assumed for this storage alternative are the same as those assumed in the centralized storage model for 153,000 metric tons.

Figure 7: Scenario and Cost Time Frames for the Centralized 70,000 Metric Ton Model



Source: GAO analysis of expert and DOE-provided data.

Model III: On-Site Storage (153,000 metric tons)

We developed this model under the assumption that total existing and newly generated nuclear waste by the private sector and DOE would be 153,000 metric tons. The stream of new waste ready to be moved to dry storage would continue through 2065. In general, the costs include the following:

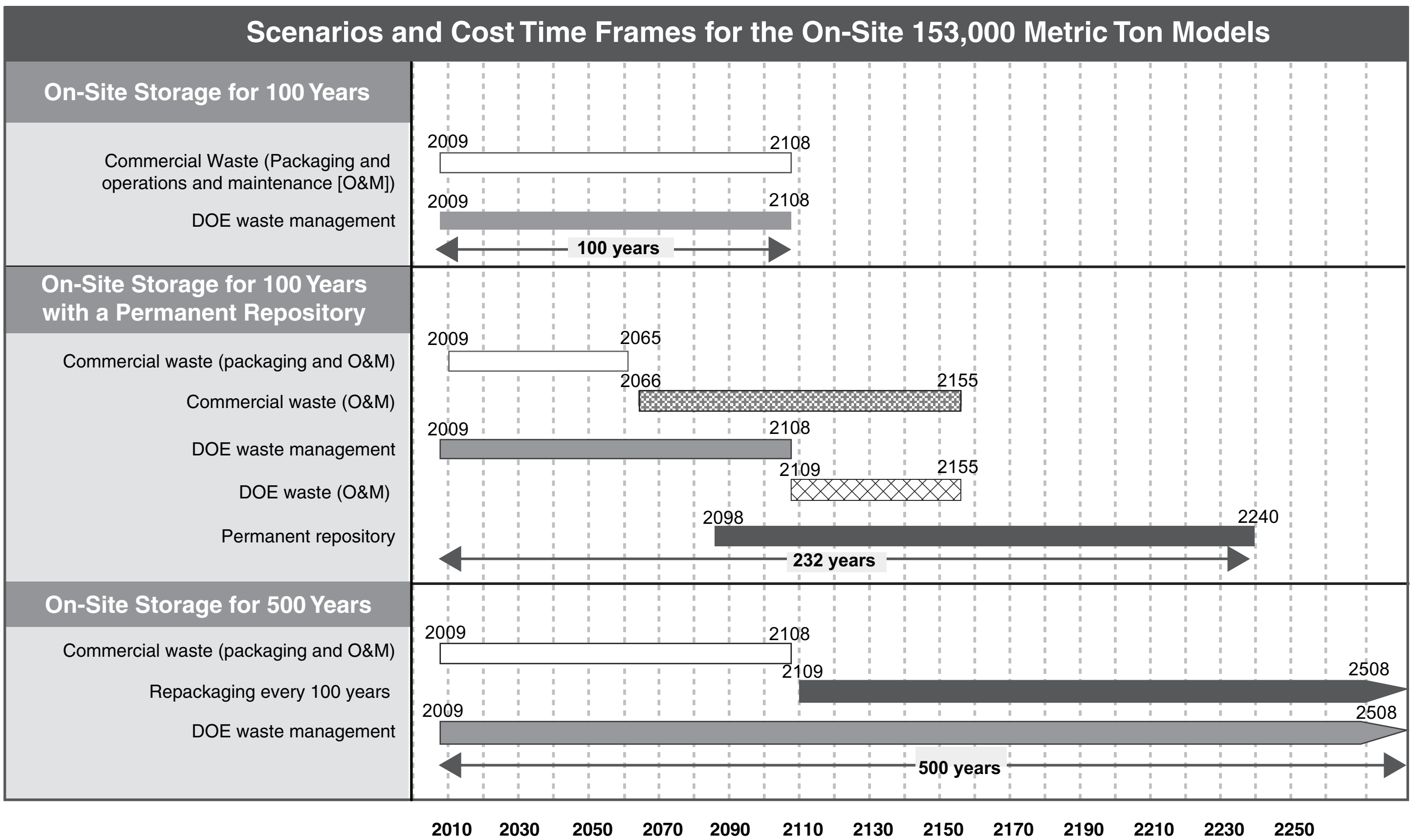
- Initial costs, which include costs of casks, costs for loading of casks, cost of loading campaigns, and operating and maintenance costs by three types of nuclear sites, i.e., operating sites with dry storage, decommissioned sites with dry storage, and decommissioned sites with wet storage. The uncertainty ranges for these costs were from plus or minus 5 percent to plus or minus 50 percent, depending on specific cost variable.

- Repackaging costs, which include the costs for casks; construction of transfer facilities, site pools, and other needed infrastructure; and repackaging campaigns. Because these costs are first incurred after 100 years and then every 100 years thereafter, they are included only in the model scenarios covering more than 100 years. The uncertainty for these costs range from plus or minus 10 percent to plus or minus 50 percent, depending on the specific cost variable.

- Dry storage pad costs, including initial costs when dry storage is first established, as well as replacement costs. Because the replacement costs are first incurred after 100 years and then every 100 years thereafter, they are included only in the model scenarios covering more than 100 years. The cost of these pads, collectively referred to as independent spent fuel

storage installations, include costs related to licensing, design, and construction of dry storage. The independent spent nuclear fuel storage installation costs have an uncertainty range of plus or minus 40 percent.

Figure 8: Scenarios and Cost Time Frames for the On-Site 153,000 Metric Ton Models

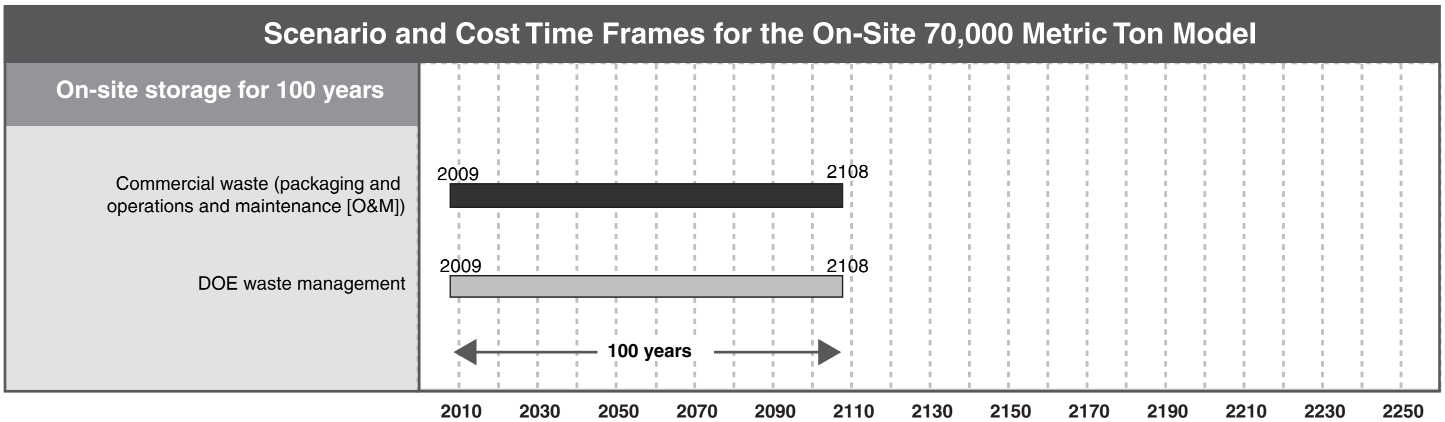


Source: GAO analysis of expert and DOE-provided data.

Model IV: On-Site Storage (70,000 metric tons)

We developed this model under the assumption that total existing and newly generated nuclear waste by the private sector and DOE will be 70,000 metric tons. The stream of new annual waste ready to be moved to dry storage will continue through 2030. The cost categories and uncertainty ranges assumed for this storage alternative are the same as those for the on-site model for storing 153,000 metric tons for 100 years.

Figure 9: Scenario and Cost Time Frames for the On-Site 70,000 Metric Ton Model



Source: GAO analysis of expert and DOE-provided data.

Costs for a Permanent Repository

For two scenarios, we assumed that at the end of 100 years the nuclear waste would be transferred to a permanent repository for disposal. To estimate the cost for a repository, we used DOE's cost data for the Yucca Mountain repository and made three adjustments to ensure compatibility with costs generated by our models. First, we included only DOE's future cost estimates for the Yucca Mountain repository. Second, because DOE provided costs in 2008 constant dollars, we converted all costs for the permanent repository to costs to 2009 present value using corresponding ranges of interest rates as previously described in this appendix. Finally, we assumed that repository construction and operating costs would be incurred from 2098 to 2240 when we added these cost ranges to our alternatives after 100 years.

Modeling Results

Table 8 shows the results of our analysis for all scenarios.

Table 8: Model Results for All Scenarios

Dollars in billions

Models and scenarios	Range of total costs[a]	Mean[a]
Permanent repository (153,000 metric tons)		
Permanent repository[b]	$41 to $67	$53
Permanent repository (70,000 metric tons)		
Permanent repository[b]	$27 to $39	$32
Model I: centralized storage (153,000 metric tons)		
Centralized 100 years	$15 to $29	$21
Centralized 100 years plus permanent repository	$23 to $81	$47
Model II: centralized storage (70,000 metric tons)		
Centralized 100 years	$12 to $20	$15
Model III: on-site storage (153,000 metric tons)		
On-site 100 years	$13 to $34	$22
On-site 100 years plus permanent repository	$20 to $97	$51
On-site for 500 years	$34 to $225	$89
Model IV: on-site storage (70,000 metric tons)		
On-site 100 years	$10 to $26	$18

Source: GAO.

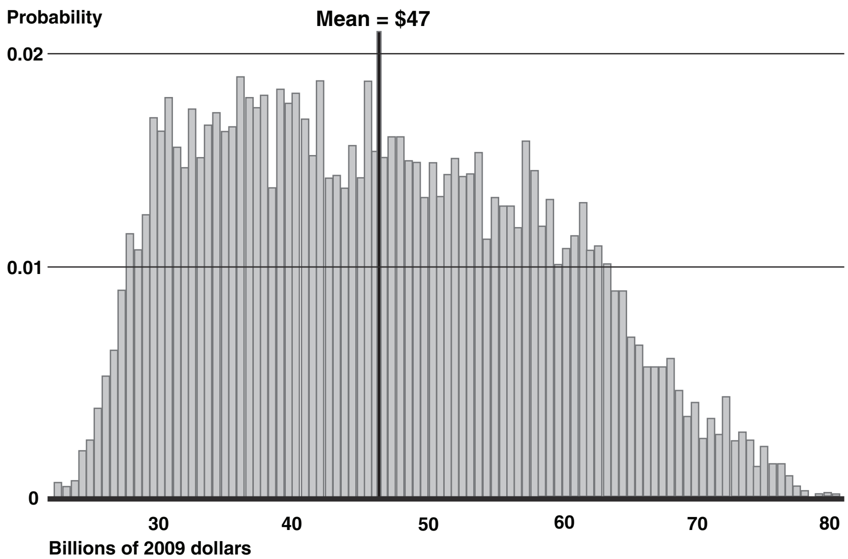
Note: All costs are in 2009 present value and represent costs regardless of who will pay or is legally responsible to pay for them and as such do not address the issue of liabilities. Furthermore, these costs do not include other potential costs, such as decommissioning and environmental costs and the government's penalties for delays in moving waste from the Idaho National Laboratory under the settlement agreement with Idaho.

[a]The cost estimates do not present exact values rather order-of-magnitude estimates as both the maximum and minimum as well as mean values will be somewhat different each time the simulation is repeated. This is because the Monte Carlo methodology will randomly select a different set of input data from one simulation run to the next.

[b]While our cost ranges for a permanent repository are based on DOE's estimate for the Yucca Mountain repository, our cost ranges differ from DOE's of $96 billion estimate for the following reasons: First, our cost ranges are in 2009 present value, while DOE uses 2007 constant dollars, which are not discounted. Our present value analysis reflects the time value of money—costs incurred in the future are worth less today—so that streams of future costs become smaller. Second, our cost ranges do not include about $14 billion in previously incurred costs. Third, our cost ranges are for 153,000 metric tons and 70, 000 metric tons of nuclear waste, while DOE's estimated cost is for 122,100 metric tons. Finally, we use ranges while DOE provides a point estimate.

Figures 10 and 11 show ranges of total costs, as well as the probabilities for two selected scenarios. In the figures, each bar indicates a range of values for total cost and the height of the each bar indicates the probability associated with those values.

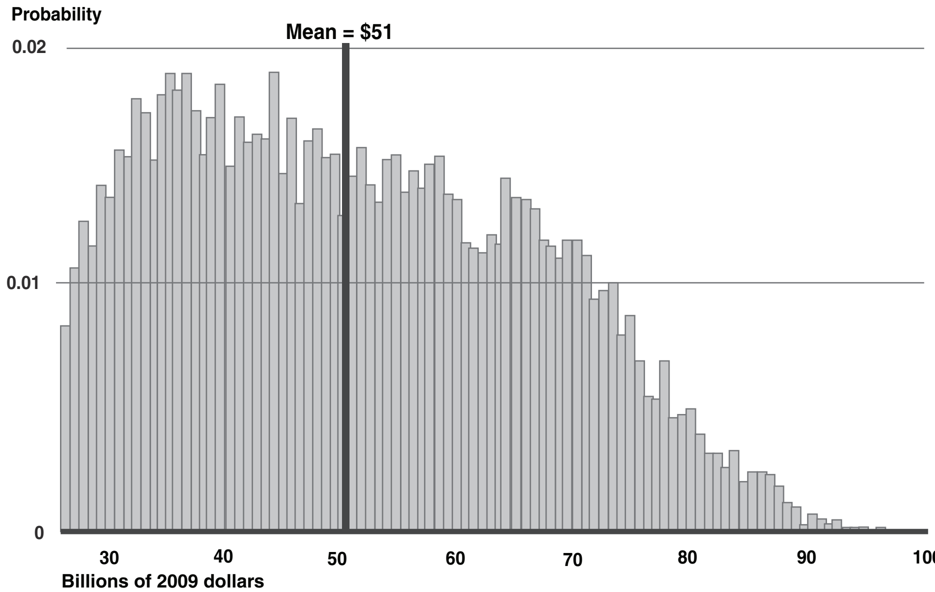
Figure 10: Total Cost Ranges for Centralized Storage for 100 Years with Final Disposition



Source: GAO analysis of expert and DOE provided data.

Note: The values on the horizontal axis of the figure are to provide a scale and do not correspond exactly to the ranges for total costs which are provided in table 8.

Figure 11: Total Cost Ranges for On-site Storage for 100 years with Final Disposition

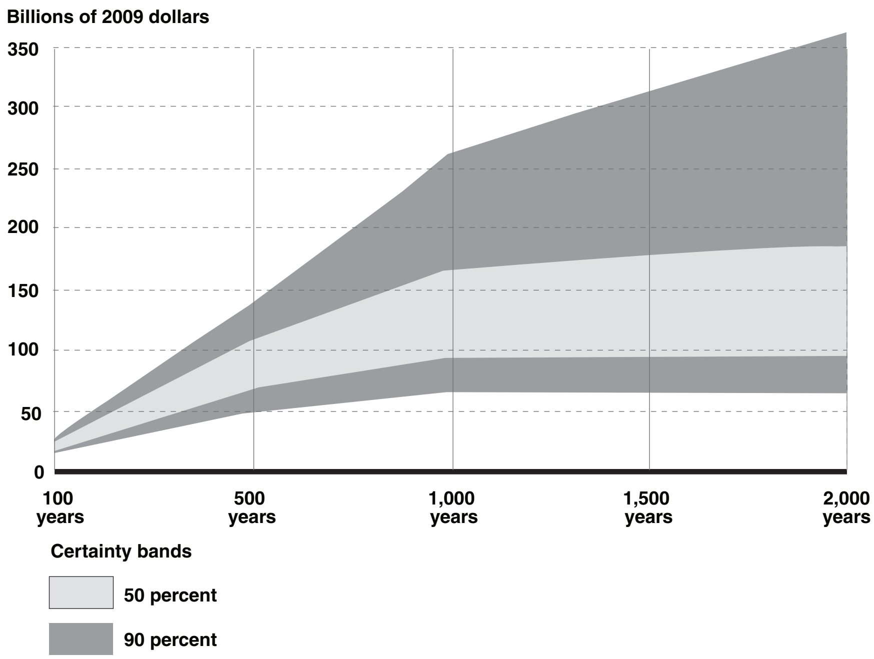


Source: GAO analysis of expert and DOE provided data.

Note: The values on the horizontal axis of the figure are to provide a scale and do not correspond exactly to the ranges for total costs which are provided in table 8.

Figure 12 shows the present value of the total cost ranges of storing the nuclear waste on site over 2,000 years. The shaded areas indicate the probability that the values fall within the indicated ranges and are the result of combinations of uncertainties from a large number of input data. Specifically, we estimate that these costs could range from $34 billion to $225 billion over 500 years, from $41 billion to $548 billion over 1,000 years, and from $41 billion to $954 billion over 2,000 years, indicating and substantial level of uncertainty in making long-term cost projections.

Figure 12: Total Cost Ranges of On-Site Storage over 2,000 Years



Source: GAO analysis of expert and DOE-provided data.

Note: The values on the vertical axis of the figure are to provide a scale and do not correspond exactly to the total cost ranges presented in table 8.

Modeling Caveats

Our models are based on ranges of average costs for each major cost category that is applicable to the alternative under analysis. As a result, the costs do not reflect storage costs for any specific site. Since we did not attempt to capture specific characteristics of each site, our values for any cost factor, if applied to any specific site, are likely incorrect. Nevertheless, since we used ranges rather than single values for a wide range of cost inputs to the models, we expect that our cost range for each variable includes the true cost for any specific site. Moreover, we expect the total cost point estimate for any scenario is within the range of total costs we developed.

Our models are designed to develop total cost ranges for each scenario within each alternative, regardless of who will pay or is legally responsible for the costs. Issues related to assignment of the costs and potentially responsible entities are discussed elsewhere in this report but are not incorporated into our ranges. Also, our cost ranges focus on actual expenditures that would be incurred over the period of analysis and do not

assume a particular funding source and do not necessarily represent costs to the federal government. Finally, because a number of cost categories are not included in our final estimated ranges, we cannot predict their impact on our final costs ranges. For example, we did not include (1) decontamination and decommissioning costs for existing facilities or facilities yet to be built within each scenario and (2) estimates for local and state taxes or fees, which would be required to establish new sites or for continued operation of on-site storage facilities after nuclear reactors are decommissioned.

Table 8 and figures 10 and 11 present the results of our analysis by individual scenario. Because the purpose of our analysis was primarily to provide cost ranges for various nuclear waste management alternatives, we did not attempt to provide a comparison of results across scenarios. For a number of reasons, we believe such a comparison would have been misleading. The alternatives we have considered are inherently different in a large number of characteristics that could not be captured in our modeling work or they were not within the scope of our analysis. For example, differences in safety, health, and environmental effects, and ease of implementation characteristics of these alternatives should have an integral role in the policy debate on waste management decisions. However, because these effects cannot be readily quantified, they were outside the scope of our modeling work and are not reflected in the total cost ranges we generated.

Appendix V: Comments from the Department of Energy

Department of Energy
Washington, DC 20585

October 28, 2009

Mr. Mark E. Gaffigan
Director, Natural Resources and Environment
U.S. Government Accountability Office
441 G Street, NW
Washington, D.C. 20548

Dear Mr. Gaffigan:

Thank you for the opportunity to review and submit comments on the draft report, "NUCLEAR WASTE MANAGEMENT: Key Attributes, Challenges and Costs for the Yucca Mountain Repository and Two Potential Alternatives" (GAO-10-48). The U.S. Department of Energy appreciates the amount of time and effort that you and your staff have taken to review this important topic.

Specific comments from Naval Reactors, the Office of General Counsel, and the Office of Environmental Management on the draft report are enclosed. If you have any questions, please feel free to call me on 202-586-6850.

Sincerely,

Christopher A. Kouts
Acting Director
Office of Civilian Radioactive
Waste Management

Enclosure

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Appendix VI: Comments from the Nuclear Regulatory Commission

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

October 26, 2009

Mr. Richard Cheston
Assistant Director
U.S. Government Accountability Office
441 G Street, N.W.
Washington, DC 20548

Dear Mr. Cheston:

Thank you for providing the U.S. Nuclear Regulatory Commission (NRC) the opportunity to review and comment on the U.S. Government Accountability Office's (GAO) draft report GAO-10-48, "NUCLEAR WASTE MANAGEMENT – Key Attributes, Challenges, and Costs for the Yucca Mountain Repository and Two Potential Alternatives." The NRC staff has reviewed the draft report. Although we did not identify any significant issues regarding accuracy, completeness, or sensitivity of information, we have separately transmitted several technical and editorial comments to your staff.

If you have any questions regarding this response, please contact Mr. Jesse Arildsen of my staff, at (301) 415-1785.

Sincerely,

R. W. Borchardt

R. W. Borchardt
Executive Director
for Operations

Enclosure:
NRC Staff Comments on Draft
Report GAO-10-48

Appendix VII: GAO Contact and Staff Acknowledgments

GAO Contact

Mark Gaffigan, (202) 512-3841 or gaffiganm@gao.gov

Staff Acknowledgments

In addition to the individual named above, Richard Cheston, Assistant Director; Robert Sánchez; Ryan Gottschall; Carol Henn; Anne Hobson; Anne Rhodes-Kline; Mehrzad Nadji; Omari Norman; and Benjamin Shouse made key contributions to this report. Also contributing to this report were Nancy Kingsbury, Karen Keegan, and Timothy Persons.

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SNC-Lavalin executives ponder company break-up at private shareholder luncheon

Beleaguered company discusses spinning off assets ahead of a potential criminal conviction

SNC-Lavalin said in an email that it "continues to evaluate all possible scenarios to create maximum value for company shareholders." *Christinne Muschi/Reuters*

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MONTREAL — Executives at SNC-Lavalin Group Inc. continue to ponder a Plan B that could see the company break up ahead of a potential criminal conviction.

David Taylor of Toronto-based Taylor Asset Management, a shareholder of SNC-Lavalin, said the embattled engineering and construction firm's CEO and chief financial officer discussed spinning off assets — which could include U.K.-based WS Atkins — at a private luncheon hosted by TD Securities in Toronto.

"They mentioned spinning off," Taylor said in an interview, referring to chief executive Neil Bruce and chief financial officer Sylvain Girard.

"They've got great assets within that are being punished and their good assets aren't being valued properly. So they sort of hypothetically talked about crystallizing that value, and the only way you can really do that is to sell," Taylor said.

The sitdown last Friday, first reported by the Globe and Mail, came a day after the company announced plans to wind down its operations in 15 countries and reported a $17-million loss in its latest quarter, precipitating a stock drop to new 10-year lows over the past few days.

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The discussion floated an alternative to a possible plan that SNC-Lavalin laid out for federal prosecutors last fall where the company would split in two, move its offices to the United States within a year and eventually eliminate its Canadian workforce if it didn't get a deal to avoid criminal prosecution.

Confidential documents, part of a PowerPoint presentation obtained by The Canadian Press in March, described something called "Plan B" — what Montreal-based SNC might have to do if it can't convince the government to grant a so-called remediation agreement to avoid criminal proceedings in a fraud and corruption case related to projects in Libya.

SNC-Lavalin said in an email that it "continues to evaluate all possible scenarios to create maximum value for company shareholders."

"We have publicly made it clear for several months that the company has a fiduciary obligation to its shareholders and employees to have a Plan B in place, retaining the services of external legal and financial advisers to help develop different scenarios for consideration," the company stated.

"That said, no decision has yet been made, so it is premature to comment further on the subject."

SNC-Lavalin bought British engineering giant WS Atkins in 2017, which now has more than 10,000 employees in Britain.

SNC hopes to sell the bulk of its 16.77 per cent stake in Highway 407 to the OMERS pension plan, with a deal expected to close before the end of June.

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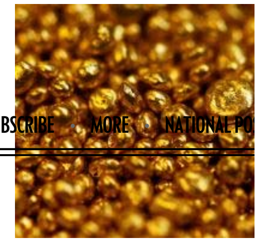

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From:	Snyder, Amy
To:	Gubbi, Veena; "Schwartz, Paul"; "Orlando, Paul"
Subject:	FOR YOUR COMMENTS- STATE OF NEW JERSEY- OYSTER CREEK- CONFORMING AMENDMENT ASSOCIATED WITH THE OYSTER CREEK GENERATING STATION LICENSE TRANSFER APPLICATION
Date:	Thursday, May 16, 2019 8:59:00 AM

Ms. Gubbi, Mr. Schwartz, and Mr. Orlando:

The U.S. Nuclear Regulatory Commission (NRC) staff plans to issue an amendment to Oyster Creek Nuclear Generating Station (Oyster Creek) at end of June 2019.

By application dated August 31, 2018 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML18243A489), including proprietary financial information provided as Enclosure 2A, "Asset Purchase and Sale Agreement By and Between Exelon Generation Company, LLC, Oyster Creek Environmental Protection, LLC, and Holtec International", Exelon Generation Company, LLC (EGC), Oyster Creek Environmental Protection, LLC (OCEP) and Holtec Decommissioning International, LLC (HDI) (together, "Applicants"), requested that the U.S. Nuclear Regulatory Commission (NRC) consent to the proposed direct transfer of the Oyster Creek Nuclear Generating Station (OCNGS) Renewed Facility Operating License No. DPR-16 and the OCNGS Independent Spent Fuel Storage Installation (ISFSI) general license (collectively referred to as the facility or Oyster Creek). Enclosure 2A of the application contains sensitive unclassified non-safeguards information (proprietary commercial and financial information) that is being withheld from public disclosure pursuant to Title 10 of the Code of Federal Regulations (10 CFR) 2.390. Specifically, the Applicants requested that the NRC consent to the direct transfer of EGC's currently licensed authority (licensed owner and operator for decommissioning) to OCEP as the licensed owner and to HDI as the licensed operator for decommissioning. In addition, the Applicants requested that the NRC approve a conforming amendment to the facility licenses to reflect this transfer from EGC to OCEP and HDI.

Exelon permanently ceased power operations at Oyster Creek on September 17, 2018 (ADAMS Accession No. ML18263A163). On September 25, 2018 (ADAMS Accession No. ML18268A258), Exelon permanently removed fuel from the Oyster Creek reactor vessel.

The proposed amendment would be a conforming amendment to reflect the license transfer from Exelon to OCEP, as the owner, and HDI, as the operator, should the NRC approve the license transfer request.
The subject application is for approval of a transfer of a license issued by the NRC and an associated conforming amendment required to reflect the approval of the transfer. Accordingly, the actions involved meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(21). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the approval of the transfer application and conforming license amendment.

If the State of New Jersey has comments on the conforming amendment, please provide the comments by June 3, 2019.

Thank you

A

Amy

Amy Snyder, Senior Project Manager
Reactor Decommissioning Branch (RDB)
Division of Decommissioning, Uranium Recovery, and Waste Programs (DUWP)
Office of Nuclear Material Safety and Safeguards (NMSS)
U.S. Nuclear Regulatory Commission (NRC)
Washington, D.C. 20555

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Fax: (301) 415-5369
Mail Stop: T5-A10
Location: T5-D48
E-mail: amy.snyder@nrc.gov

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION AND OFFICE OF NUCLEAR MATERIAL SAFETY AND SAFEGUARDS

RELATED TO REQUEST FOR DIRECT TRANSFER OF CONTROL OF RENEWED FACILITY OPERATING LICENSE NO. DPR-16 AND THE GENERAL LICENSE FOR THE INDEPENDENT SPENT FUEL STORAGE INSTALLATION

FROM EXELON GENERATION COMPANY, LLC

TO OYSTER CREEK ENVIRONMENTAL PROTECTION, LLC AND HOLTEC DECOMMISSIONING INTERNATIONAL, LLC

OYSTER CREEK NUCLEAR GENERATING STATION

DOCKET NOS. 50-219 AND 72-15

1.0 INTRODUCTION

By letter dated August 31, 2018 (Agencywide Documents Access and Management System [ADAMS] Accession No. ML18243A489), including proprietary financial information provided as Enclosure 2A, “Asset Purchase and Sale Agreement By and Between Exelon Generation Company, LLC, Oyster Creek Environmental Protection, LLC, and Holtec International” (ADAMS Accession No. ML18243A490), Exelon Generation Company, LLC (EGC), Oyster Creek Environmental Protection, LLC (OCEP) and Holtec Decommissioning International, LLC (HDI) (together, “Applicants”), requested that the U.S. Nuclear Regulatory Commission (NRC) consent to the proposed direct transfer of the Oyster Creek Nuclear Generating Station (Oyster Creek) Renewed Facility Operating License No. DPR-16 and the Oyster Creek Independent Spent Fuel Storage Installation (ISFSI) general license (collectively referred to as the facility or Oyster Creek). Specifically, the Applicants requested that the NRC consent to the direct transfer of EGC’s currently licensed authority (licensed owner and operator for decommissioning) to OCEP as the licensed owner and to HDI as the licensed operator for decommissioning. This direct transfer request is submitted to the NRC for approval pursuant to Section 184 of the Atomic Energy Act of 1954, as amended (AEA), “Inalienability of Licenses,” and Title 10 of the *Code of Federal Regulations* (10 CFR) 50.80, “Transfer of licenses,” 10 CFR 72.50, “Transfer of licenses,” and 10 CFR 50.90, “Application for amendment of license, construction permit, or early site permit.” Enclosure 2A of the application contains sensitive unclassified non-safeguards information (proprietary commercial and financial information) that is being withheld from public disclosure pursuant to 10 CFR 2.390.

In addition, the Applicants requested that the NRC approve a conforming amendment to the facility licenses to reflect this transfer from EGC to OCEP and HDI.

Following approval and implementation of the proposed direct transfer of control of the license, HDI will assume licensed responsibility as the operator of Oyster Creek, and OCEP will assume licensed responsibility as the owner of Oyster Creek. OCEP will enter into a

decommissioning operator services agreement with HDI, which will provide for HDI to act as OCEP's agent and for OCEP to pay HDI's costs of post-shutdown operations, including all decommissioning and spent fuel management costs.

Notice of NRC consideration[1] of the application was published in the *Federal Register* (FR) on October 19, 2018 (83 FR 53119) and included an opportunity to comment, request a hearing, and petition for leave to intervene. At the request of a Member of the U.S. Senate, as published in the FR on December 10, 2018 (83 FR 63544), the NRC reopened the comment period for an additional 30 days to allow more time for members of the public to develop and submit comments. The staff (the staff) reviewed the questions and comments received and considered them in the review process, as discussed in Section 12.0 of this safety evaluation. The themes of the questions and comments that were in the scope of the NRC's review, such as decommissioning funding and financial qualifications of Holtec, its partners, and subsidiaries, are addressed in this safety evaluation.

2.0 BACKGROUND

The Oyster Creek site is located approximately two miles south of Forked River, New Jersey, in Ocean County. Oyster Creek employed a Boiling Water Reactor (BWR-2) with a Mark I type containment licensed to generate 1,930 megawatts (thermal energy). The operating license for Oyster Creek was issued on April 9, 1969, and commercial operation commenced on December 23, 1969. The license was renewed on April 9, 2009.

By letter dated January 7, 2011 (ADAMS Accession No. ML110070507), "Certification of Permanent Cessation of Power Operations for Oyster Creek Nuclear Generating Station," EGC notified the NRC of its intent to prematurely and permanently cease power operations at Oyster Creek no later than December 31, 2019, pursuant to 10 CFR 50.82(a)(1)(i).

Pursuant to 10 CFR 50.75(f)(3) and 10 CFR 50.54(bb), EGC submitted a Preliminary Decommissioning Cost Estimate (PDCE) and Irradiated Fuel Management Plan (commonly referred to as the Spent Fuel Management Plan or SFMP) to the NRC on December 30, 2014 (ADAMS Accession No. ML14365A067), as supplemented by letter dated April 5, 2016, in a response to a request for additional information (ADAMS Accession No. ML16096A397). The NRC completed its review by letter dated July 6, 2016 (ADAMS Accession No. ML16131A750).

By letter dated February 14, 2018 (ADAMS Accession No. ML18045A084), EGC revised its certification to permanently cease power operations at Oyster Creek no later than October 31, 2018, pursuant to 10 CFR 50.82(a)(1)(i). Because of its decision to retire Oyster Creek one year earlier, and related changes to the anticipated schedule of decommissioning and spent fuel management activities, by letter dated May 21, 2018 (ADAMS Accession No. ML18141A486), EGC updated the Oyster Creek SFMP accordingly. Additionally, by letter dated May 21, 2018 (ADAMS Accession No. ML18141A775), EGC submitted for review the Post Shutdown Decommissioning Activities Report (2018 PSDAR), including the Site-Specific Decommissioning Cost Estimate (DCE), for Oyster Creek to the NRC. The 2018 PSDAR was submitted in accordance with the requirements of 10 CFR 50.82, "Termination of license," paragraph (a)(4)(i).

[1] This *FR* Notice has information regarding how to access sensitive unclassified non-safeguards information for contention preparation. No requests for such information were made.

The NRC completed its review of the updated Oyster Creek SFMP and PSDAR by letter dated December 17, 2018 (ADAMS Accession No. ML18241A068). This letter includes the NRC's continued approval of the Oyster Creek SFMP.

On September 25, 2018 (ADAMS Accession No. ML18268A258), pursuant to 10 CFR 50.82(a)(1)(ii), EGC certified to the NRC that it had permanently ceased operations at Oyster Creek on September 17, 2018, and that all fuel had been permanently removed from the reactor vessel and placed in the spent fuel pool. Exelon certified these actions and used an alternate method[2] for complying with the oath or affirmation requirement for certification as presented in the United States Code, Title 28, Section 1746 (28 USC 1746). In accordance with the 2018 PSDAR, EGC placed the Oyster Creek reactor in SAFSTOR[3] and planned to have all Oyster Creek spent fuel in dry storage in the onsite ISFSI by 2020, terminate the 10 CFR Part 50 license by 2078, and restore the site by 2080.

Application for License Transfer

According to the license transfer application, the purpose of the proposed transfer of the licenses is to permit the prompt radiological decommissioning of the non-ISFSI portions of the Oyster Creek site. Following approval and implementation of the license transfer, OCEP will purchase Oyster Creek and assume licensed responsibility as its owner. OCEP will enter into a decommissioning operator services agreement for decommissioning services with HDI, which provides for HDI to act as OCEP's agent and for OCEP to pay for all of HDI's costs of decommissioning, spent fuel management, and site restoration. Accordingly, HDI will become the licensed operator for decommissioning.

As the licensed operator, HDI will contract with Comprehensive Decommissioning International (CDI), a company jointly formed and owned by Holtec International (Holtec) and SNC-Lavalin Group (SNC-Lavalin). SNC-Lavalin, a foreign corporation, holds its interest in CDI through a wholly-owned U.S. subsidiary, Kentz USA Inc. CDI is majority owned by Holtec. Both Holtec and SNC-Lavalin are transferring employees to CDI. Pursuant to a Decommissioning General Contractor Agreement between HDI and CDI, CDI will manage and perform the day-to-day Oyster Creek licensed activities, including decommissioning activities, subject to HDI's direct oversight and control as the licensed operator.

Asset Purchase and Sale Agreement

According to the license transfer application, OCEP proposes to purchase Oyster Creek pursuant to the terms of an Asset Purchase and Sale Agreement (PSA) between EGC, OCEP, and Holtec. A copy of the PSA is provided in a separately-bound Addendum as Enclosure 2A to the
August 31, 2018, application. Enclosure 2A contains confidential commercial and financial information that is being withheld from public disclosure pursuant to 10 CFR 2.390. A redacted, non-proprietary version of the PSA is provided as Enclosure 2 of the application.

[2] This alternate method is discussed in Regulatory Information Summary 2001-01-18, RIS 01-018: "Requirements for Oath or Affirmation", dated August 22, 2001.
[3] SAFSTOR is a method of decommissioning in which a nuclear facility is placed and maintained in a condition that allows the facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use.

Revised PSDAR

In accordance with 10 CFR 50.82(a)(7), by letter dated September 28, 2018 (ADAMS Accession No. ML18275A116), HDI submitted a "Notification of Revised Post-Shutdown Decommissioning Activities Report and Revised Site-Specific Decommissioning Cost Estimate for Oyster Creek Nuclear Generating Station," (revised PSDAR) to notify the NRC of changes and its intention to accelerate the schedule for the prompt decommissioning of Oyster Creek and unrestricted release of all portions of the site (excluding the ISFSI) within eight (8) years after license transfer. The revised PSDAR is based on and contingent upon NRC approval of this license transfer, and Oyster Creek being acquired by OCEP, pursuant to the terms of the PSA. On November 9, 2018 (ADAMS Accession No. ML18282A035), the NRC notified EGC that the staff is treating the revised PSDAR submittal dated September 28, 2018, as a supplement to the Oyster Creek license transfer application dated August 31, 2018, until such time as the NRC makes a regulatory decision regarding the Oyster Creek license transfer application.

3.0 REGULATORY EVALUATION

As described in the application, the proposed transaction constitutes a transfer of ownership interest of Oyster Creek, which requires prior NRC approval. For direct transfers of control of a license, the NRC must find that the direct transfer of the license is otherwise consistent with applicable provisions of law, NRC regulations, and orders issued by the Commission.

The request for approval of the transfer of the Oyster Creek license as described above, and as discussed in this safety evaluation, is made pursuant to 10 CFR 50.80(a), which states that:

> No license for a production or utilization facility (including, but not limited to, permits under this part and part 52 of this chapter, and licenses under parts 50 and 52 of this chapter), or any right thereunder, shall be transferred, assigned, or in any manner disposed of, either voluntarily or involuntarily, directly or indirectly, through transfer of control of the license to any person, unless the Commission gives its consent in writing.

In addition, the regulations in 10 CFR 50.80(b) and (c) apply. The regulation at 10 CFR 50.80(b) states, in part:

> (1) An application for transfer of a license shall include:
>
> (i) For a construction permit or operating license under this part, as much of the information described in 50.33 and 50.34 of this part with respect to the identity and technical and financial qualifications of the proposed transferee as would be required by those sections if the application were for an initial license.

Section 50.80(c) of 10 CFR states, in part, that:

> …the Commission will approve an application for the transfer of a license, if the Commission determines: (1) That the proposed transferee is qualified to be the holder of the license; and (2) That transfer of the license is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission pursuant thereto.

Section 50.33(f) of 10 CFR states, in part, that:

> Except for an electric utility applicant for a license to operate a utilization facility of the type described in § 50.21(b) or § 50.22, [each application shall state] information sufficient to demonstrate to the Commission the financial qualification of the applicant to carry out, in accordance with regulations in this chapter, the activities for which the permit or license is sought.

The staff applies guidance in NUREG-1577, Revision 1, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance" (ADAMS Accession No. ML013330264), issued February 1999, to evaluate the financial qualifications of applicants to carry out the activities for which the permit or license is sought.

Section 50.54(bb) of 10 CFR requires, in part, a licensee to submit, for NRC review and preliminary approval, the program by which the licensee intends to manage and provide funding for the management of all irradiated fuel at the reactor following permanent cessation of operation of the reactor until title to the irradiated fuel and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository.

In accordance with 10 CFR 50.2, "Decommission," means to remove a facility or site safely from service and reduce residual radioactivity to a level that permits (1) release of the property for unrestricted use and termination of the license, or (2) release of the property under restricted conditions and termination of the license.

Section 50.33(k)(1) of 10 CFR requires that applicants provide information, in the form of a report, as described in 10 CFR 50.75, "Reporting and recordkeeping for decommissioning planning," indicating how reasonable assurance will be provided that funds will be available to decommission the facility.

Section 50.75 of 10 CFR establishes requirements for indicating to NRC how a licensee will provide reasonable assurance that funds will be available for the decommissioning process. Section 50.75(b) requires that each power reactor applicant for an operating license submit a decommissioning report, as required by Section 50.33(k). Section 50.75(e) provides the methods acceptable to the NRC for providing decommissioning financial assurance. Finally, Section 50.75(h) provides additional requirements regarding the management of decommissioning trust funds.

Section 50.82(a)(8)(i) of 10 CFR states that decommissioning trust funds may be used by licensees if:

> (A) The withdrawals are for expenses for legitimate decommissioning activities consistent with the definition of decommissioning in § 50.2;
>
> (B) The expenditure would not reduce the value of the decommissioning trust below an amount necessary to place and maintain the reactor in a safe storage condition if unforeseen conditions or expenses arise and;
>
> (C) The withdrawals would not inhibit the ability of the licensee to complete funding of any shortfalls in the decommissioning trust needed to ensure the availability of funds to ultimately release the site and terminate the license.

Section 50.82(a)(8)(v) of 10 CFR requires power reactor licensees that have permanently ceased operations to provide to the NRC annually, by March 31, a decommissioning financial assurance status report.

Section 50.82(a)(8)(vii) of 10 CFR provides, in part, for the licensee's annual submittal to the NRC, a report on the status of its funding for managing irradiated fuel.

Section 50.34(b)(7) of 10 CFR requires applicants to provide: The technical qualifications of the applicant to engage in the proposed activities in accordance with the regulations in this chapter.

The staff applies guidance in NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition," Chapter 13, "Conduct of Operations," Revision 6 of Section 13.1.1, "Management and Technical Support Organization" (ADAMS Accession No. ML15005A449), for the review of the corporate-level management and technical support organization of applicants. Guidance in Revision 7 of Section 13.1.2 and 13.1.3, "Operating Organization" (ADAMS Accession No. ML15007A296), is applied for the review of the operating organization of applicants, including the structure, functions, and responsibilities of the onsite organization established to safely operate and maintain the facility.

In addressing foreign ownership, control, or domination (FOCD) issues, Section 103d of the AEA provides, in relevant part that:

> No license may be issued to…any corporation or other entity if the Commission knows or has reason to believe it is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government.

The NRC's regulation in 10 CFR 50.38 is the regulatory provision that implements the FOCD provision of the AEA. Section 50.38 of 10 CFR provides, in part, that:

> [A]ny corporation, or other entity which the Commission knows or has reason to believe is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government, shall be ineligible to apply for and obtain a license.

The staff evaluates license transfer applications in a manner consistent with the guidance provided in the "Final Standard Review Plan on Foreign Ownership, Control, or Domination," as published in the *Federal Register* on September 28, 1999 (64 FR 52357), to determine whether the applicant is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government.

The staff also reviews information that relates to nuclear onsite property damage insurance requirements under 10 CFR 50.54(w) and the Price-Anderson insurance and indemnity requirements under Section 170 of the AEA and 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements."

With respect to the transfer of control of a license for an ISFSI, 10 CFR 72.50(a) states that:

> No license or any part included in a license issued under this part for an ISFSI or MRS [Monitored Retrievable Storage Installation] shall be transferred, assigned, or in any manner disposed of, either voluntarily or involuntarily,

directly or indirectly, through transfer of control of the license to any person, unless the Commission gives its consent in writing.

Finally, with respect to the requested conforming license amendment, 10 CFR 50.90 states, in part, whenever a holder of a license, including a construction permit and operating license under this part, desires to amend the license or permit, an application for an amendment must be filed with the Commission fully describing the changes desired and following as far as applicable the form prescribed for original applications. Pursuant to 10 CFR 2.1315, where administrative license amendments are necessary to reflect an approved license transfer, such amendments will be included in the order that approves the license transfer.

4.0 FINANCIAL EVALUATION

4.1 Financial Qualifications

As described in this evaluation, on September 25, 2018, pursuant to 10 CFR 50.82(a)(1)(ii), EGC certified to the NRC that it had permanently ceased operations at Oyster Creek on September 17, 2018, and that all fuel had been permanently removed from the reactor vessel and placed in the spent fuel pool. Since HDI, as the proposed licensed operator for decommissioning, will not be authorized under the facility license to operate or load fuel in the reactor pursuant to the terms of 10 CFR 50.82(a)(2), HDI will not conduct the reactor operations contemplated by the financial qualifications provisions of 10 CFR 50.33(f)(2), but rather all of its licensed activities will involve possession of radioactive material in connection with maintaining the safe condition of the plant, radiological decommissioning of the Oyster Creek site (including the ISFSI), license termination, and operational responsibilities associated with spent fuel management.

Thus, following the proposed transfer, OCEP (the proposed licensed owner) will maintain the existing Nuclear Decommissioning Trust (NDT) and will be responsible for funding all the expenses associated with radiological decommissioning of Oyster Creek and operational costs for spent fuel management. Accordingly, as described in this safety evaluation, the staff's review of the Applicants' financial qualifications and decommissioning financial assurance pursuant to 10 CFR 50.33(f), 10 CFR 50.33(k)(1), 10 CFR 50.75, and 10 CFR 50.82(a), includes an analysis of the projected costs for decommissioning the facility and terminating the license, and managing irradiated fuel until the U.S. Department of Energy (DOE) takes title and possession of the fuel.

For a facility in decommissioning, a licensee is required to execute financial plans for spent fuel management under 10 CFR 50.54(bb) and report annually on the status of funding dedicated towards radiological decommissioning and spent fuel management under 10 CFR 50.82(a)(8)(v) to (vii).

4.2 Radiological Decommissioning

Pursuant to NRC regulations in 10 CFR 50.2, "Decommission," means to remove a facility or site safely from service and reduce residual radioactivity to a level that permits: (1) release of the property for unrestricted use and termination of the license, or (2) release of the property under restricted conditions and termination of the license. The existing NDT for Oyster Creek was created in compliance with 10 CFR 50.75, and the funds within the trust were collected while the facility was operating. As described below, the staff's review of decommissioning financial assurance assesses whether the Applicants have provided reasonable assurance of

obtaining the funds necessary to cover estimated costs for radiological decommissioning of Oyster Creek and its ISFSI.

Separate from this application, by letter dated September 28, 2018, the Applicants provided a revised PSDAR[4] in support of the proposed transfer (ADAMS Accession No. ML18275A116). Specifically, the revised PSDAR contained:

1. A description of the planned, accelerated decommissioning activities along with a schedule for their accomplishment;
2. A discussion that provides the reasons for concluding that the environmental impacts associated with site-specific decommissioning activities will be bounded by previously issued environmental impact statements (EIS); and
3. A site-specific decommissioning cost estimate, including the projected irradiated fuel management costs, license termination costs, and site restoration costs.

The 2018 PSDAR, as originally submitted by EGC, reflected the current Oyster Creek decommissioning plan, to be completed by EGC within a 60-year period using the SAFSTOR method. The revised PSDAR reflects OCEP's plan to complete the immediate and accelerated decommissioning of the non-ISFSI portions of the Oyster Creek site within an 8-year period after the proposed transfer is approved. The revised PSDAR also contains the most recent decommissioning cost estimate and spent fuel management plans pursuant to 10 CFR 50.82, "Termination of License."

Under the revised PSDAR, as compared to EGC's 2018 PSDAR, the proposed change in decommissioning method from SAFSTOR to DECON results in approximately an overall 50-year acceleration of the site closure, a site-specific decommissioning cost estimate that reflects a license termination cost reduction in an amount of approximately $480 million, and a decrease in spent fuel management costs of approximately $65 million. Following site decommissioning, HDI plans to request to amend its NRC license to limit applicability of the license to that portion of the site where the ISFSI containing the spent fuel and Greater than Class C (GTCC) waste is located, with the remainder of the site being released for unrestricted use. Spent fuel storage operations will continue at the site, independent of decommissioning operations, until the transfer of the fuel to the DOE is complete.

Once the fuel and the GTCC waste are removed from the site, HDI plans to decommission the ISFSI and terminate its NRC license and release the site for unrestricted use. In accordance with the specific requirements of 10 CFR § 72.30 for ISFSI decommissioning, the cost estimate for decommissioning the ISFSI reflects: 1) the cost of HDI's decommissioning contractor performing the decommissioning activities; 2) a contingency allowance of 25%; and 3) the cost of meeting the criteria for unrestricted use. The cost summary for decommissioning the ISFSI is presented in Appendix A of the revised PSDAR.

As part of its review of the application, the staff reviewed the revised site-specific DCE for Oyster Creek included with the revised PSDAR and found that it contains the appropriate information, pursuant to NUREG-1713, "Standard Review Plan for Decommissioning Cost Estimates for Nuclear Power Reactors," to perform an evaluation including:

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[4] The staff notes that the NRC does not review the PSDAR for approval; however, for the purpose of this license transfer request, the staff relied on the revised PSDAR as a reference for the Applicants' decommissioning plans.

- A description of the decommissioning cost estimating methodology
- A description of the overall decommissioning project annual expenses
- A summary decommissioning cost estimate by major activity and phase
- A schedule of the major decommissioning activities
- A summary of the radiological D&D management with support staff levels
- An estimate of the radioactive waste volume

Based on the review of the revised site-specific DCE, in accordance with NUREG-1713, and in comparison to the original EGC 2018 PSDAR and site-specific DCE, the staff finds that the Applicants' revised site-specific DCE for Oyster Creek appears reasonable.

In its application dated August 31, 2018, the Applicants provided financial projections for the duration of the Oyster Creek decommissioning project, including the amount of the decommissioning trust funds in the NDT. The application also included a cash flow analysis that assumes a NDT balance of approximately $848 million (as of January 1, 2019), as well as estimated costs for radiological decommissioning, including the Oyster Creek ISFSI[5] (~$618 million), spent fuel management, and site restoration of Oyster Creek, all to be funded using the NDT. With respect to the adequacy of funding for the radiological decommissioning of Oyster Creek and the Oyster Creek ISFSI, the staff reviewed the application, including the proposed site-specific decommissioning cost estimate for the facility, planned decommissioning activities, the most conservative opening NDT balance in 2019 ($848 million), and projected trust growth. In its analysis, the staff considered the NDT opening balance of $848 million and a 2% real-rate of return on annual balances. These considerations were included in the staff's independent cash flow analysis is contained in Attachment 1 to this safety evaluation. Based on its evaluation as shown in its cash flow analysis, the staff finds that the funds in the NDT are expected to be available and sufficient to cover the estimated costs for the radiological decommissioning of the facility (including the ISFSI).

On November 30, 2018 (ADAMS Accession No. ML18334A215), pursuant to 10 CFR 50.12, "Specific exemptions," HDI requested an exemption from 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(1)(iv) for Oyster Creek to allow use of a portion of the funds from the Oyster Creek NDT for the management of spent fuel and site restoration activities. Additionally, HDI requested an exemption from 10 CFR 50.75(h)(1)(iv) for all Oyster Creek NDT disbursements for spent fuel management and site restoration costs to be made without prior notice, similar to withdrawals in accordance with 10 CFR 50.82(a)(8). The staff's analysis of this regulatory exemption (ADAMS Accession No. ML19170A275) was performed separate from this safety evaluation and, on June 20, 2019, the staff approved the exemption request. This exemption is being issued simultaneously with this license transfer and will only apply to OCEP and HDI following consummation of the license transfer transaction and NRC issuance of the conforming amendment reflecting this license transfer.

In its review of the exemption, the staff concluded that reasonable assurance exists that adequate funds will be available in the NDT to complete radiological decommissioning, license

[5] According to the most recent Decommissioning Funding Status Report for Oyster Creek, dated April 1, 2019 (ADAMS Accession No. ML19091A140), the estimated cost to radiologically decommission the Oyster Creek ISFSI is approximately $5.994 million.

termination, spent fuel management, and site restoration activities within the scope of the exemption request. The staff's findings from its evaluation of the exemption were considered in its analysis of this proposed license transfer and supports the staff's conclusion that the Applicants' use of the NDT for activities associated with spent fuel management and other, non-radiological activities such as site restoration, will not negatively impact availability of funding for radiological decommissioning.

Conclusion

Based on this review, in consideration of the above analysis and the staff's independent cash flow analysis in Attachment 1 to this safety evaluation, the staff finds that OCEP and HDI have provided reasonable assurance of obtaining the funds necessary to cover estimated costs for decommissioning Oyster Creek and its ISFSI in accordance with the requirements of 10 CFR 50.33(f), 10 CFR 50.33(k)(1), 10 CFR 50.75, and 10 CFR 50.82(a).

4.3 Spent Fuel Management

After the closing of the proposed transaction, OCEP will retain ownership and title to all spent nuclear fuel and all rights and obligations under the Standard Spent Fuel Disposal Contract (see Section 5.0, "Standard Contract for Disposal of Spent Nuclear Fuel," of this safety evaluation, for further discussion on this topic).

With regard to spent fuel removal from the reactor site, HDI indicated that its plan for spent fuel removal is consistent with the Oyster Creek SFMP previously submitted by EGC[6] and approved by staff,[7] in that fuel is expected to be removed beginning in 2034. This plan remains dependent upon the DOE's ability to remove spent fuel from the site in a timely manner. According to the Oyster Creek SFMP, assuming the DOE's generator allocation/receipt schedules are based upon the oldest fuel receiving the highest priority and that the DOE begins removing spent fuel from commercial facilities in 2025 with an annual capacity of 3,000 metric tons of uranium, spent fuel is projected to remain at the Oyster Creek site for approximately 16 years after the termination of operations. Any delay in transfer of fuel to DOE or decrease in the rate of acceptance will correspondingly prolong the transfer process and result in spent fuel remaining at the site longer than anticipated. Accordingly, in Section 3.3 of Enclosure 1 of its revised Oyster Creek PSDAR, "Oyster Creek Nuclear Power Station Revised Site-Specific Decommissioning Cost Estimate," HDI based its cost assumptions regarding fuel removal from Oyster Creek in the years 2034 through 2035. The NRC staff accepts these assumptions with regards to the final disposition of Oyster Creek spent fuel as the DOE, per the Nuclear Waste Policy Act of 1982, is authorized to ultimately enter into contracts with owners and generators of commercial spent nuclear fuel to begin taking title to (legal ownership of) spent nuclear fuel. Spent fuel storage operations will continue at the site, independent of decommissioning operations, until the transfer of the fuel to the DOE is complete.

In its license transfer application, dated August 31, 2018, the Applicants provided their funding plan for spent fuel management costs, which included using excess decommissioning trust funds for spent fuel management. The staff's review of the Applicants' funding plan for spent fuel management costs is discussed below.

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[6] ADAMS Accession No. ML18141A486
[7] ADAMS Accession No. ML18226A330

Exemption to use NDT for Spent Fuel Management

The Applicants proposed to use excess decommissioning funds for spent fuel management expenses, relying on a regulatory exemption. By letter dated November 30, 2018, HDI requested an exemption from 10 CFR 50.82(a)(8)(i)(A) for Oyster Creek to allow use of a portion of the funds from the Oyster Creek NDT for the management of spent fuel and site restoration activities. As mentioned above, the staff's analysis of this regulatory exemption was performed separate from this safety evaluation and, on June 20, 2019, the staff approved the exemption request (ADAMS Accession No. ML19170A275). This exemption is being issued simultaneously with this license transfer and will only apply to OCEP and HDI following consummation of the license transfer transaction and NRC issuance of the conforming amendment reflecting this license transfer. In its review of the exemption, the staff concluded that reasonable assurance exists that adequate funds will be available in the NDT to complete radiological decommissioning, license termination, spent fuel management, and site restoration activities within the scope of this exemption request. The staff's findings from its evaluation of the exemption were considered in its analysis of this proposed license transfer and supports the staff's conclusion that the Applicants' use of the NDT for activities associated with spent fuel management and other, non-radiological activities such as site restoration, will not negatively impact availability of funding for radiological decommissioning. These findings are supported by the staff's independent cash flow analysis.

Based on its evaluation, the staff finds that the use of excess funds from the NDT for spent fuel management, provides a reasonable source of funding to cover the costs associated with spent fuel management because such use will not have a negative impact on the adequacy of funding for radiological decommissioning, as confirmed by the regulatory exemption described above.

Conclusion

The staff reviewed estimates for major spent fuel management activities and funding requirements. Based on its review, the staff concludes that the activities and associated costs of the Oyster Creek SFMP appear reasonable, and as noted above, the staff accepts the assumptions in the Oyster Creek SFMP with regard to the final disposition of Oyster Creek spent fuel by DOE. In addition, the staff does not have new information that challenges the preliminary approval of the Oyster Creek SFMP previously granted by NRC.

Pertaining to the Applicants' plan to fund spent fuel management activities from the NDT, the staff reviewed the Applicants' proposed site-specific decommissioning cost estimate for the facility, planned decommissioning activities and funding associated with those activities, and use of the NDT for spent fuel management (~$225 million) through 2035.[8] The staff assumed a conservative opening 2019 NDT balance of $848 million, based upon actual NDT balance data for Oyster Creek, and a projected NDT growth rate of 2% real rate of return on annual balances. Based on its evaluation, the staff finds that funds are expected to be available to pay for the radiological decommissioning of the facility (including the ISFSI), spent fuel management, and site restoration, as allowed by the approval of the regulatory exemption. The staff's independent cash flow analysis is contained in Attachment 1 to this safety evaluation report.

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[8] According to the Oyster Creek SFMP, spent fuel is projected to be removed from the Oyster Creek site by DOE by the end of 2034.

Based on its review, and in consideration of the above analysis describing the Applicants' financial plans for managing spent fuel, the staff finds that the OCEP and HDI have reasonable assurance of obtaining the funds necessary to cover estimated costs for irradiated fuel management in accordance with 10 CFR 50.33(f) and 10 CFR 50.54(bb).

4.4 Financial Qualifications Conclusion

As described above, the staff reviewed the application in its evaluation of the Applicants' financial qualifications, funding for the decommissioning of Oyster Creek, and funding for irradiated fuel management at Oyster Creek. Based on its evaluation as described above and shown in its cash flow analysis, the staff concludes that the funds in the NDT are expected to be available and sufficient to cover the estimated costs for the radiological decommissioning of the facility (including the ISFSI). Therefore, the staff concludes that the Applicants have provided reasonable assurance of obtaining the funds necessary to cover estimated costs for decommissioning Oyster Creek in accordance with the requirements of 10 CFR 50.33(f), 10 CFR 50.33(k)(1), 10 CFR 50.75, and 10 CFR 50.82(a).

In addition, based on its evaluation above of the Applicants' funding plans for managing spent fuel, including the regulatory exemption to use the NDT for spent fuel management, as supported by the staff's independent cash flow analysis, the staff concludes that the OCEP and HDI have reasonable assurance of obtaining the funds necessary to cover estimated costs for spent fuel management in accordance with the requirements of 10 CFR 50.33(f), and 10 CFR 50.54(bb).

Accordingly, considering the foregoing evaluation, the staff finds that OCEP and HDI are financially qualified to hold the Oyster Creek License No. DPR-16, as proposed.

5.0 STANDARD CONTRACT FOR DISPOSAL OF SPENT NUCLEAR FUEL

Upon closing, OCEP will hold title to the spent nuclear fuel at Oyster Creek and will maintain the DOE Standard Contract, including all rights and obligations under that contract. This Standard Contract, No. DE-CR01-83NE-44385 (DOE Standard Contract), was entered into by the previous owner, GPU Nuclear, Inc., then known as "GPU Nuclear Corporation," on behalf of itself and Jersey Central Power & Light Company, and the United States of America, represented by the DOE, to govern the disposal of spent nuclear fuel generated at Oyster Creek. HDI will have exclusive responsibility under the Licenses for the possession, maintenance, and decommissioning of Oyster Creek, which includes responsibility for spent fuel management and the maintenance and security of the ISFSI.

6.0 ANTITRUST REVIEW

The AEA does not require or authorize antitrust reviews of post-operating license transfer applications (*Kansas Gas and Electric Co., et al.* (Wolf Creek Generating Station, Unit 1), CLI- 99-19, 49 NRC 441 (1999)). This application postdates the issuance of the operating license for the unit under consideration in this safety evaluation, and, therefore, no antitrust review is required or authorized.

7.0 FOREIGN OWNERSHIP, CONTROL, OR DOMINATION

Sections 103d and 104d of the AEA prohibit the NRC from issuing a license for a nuclear power plant to "any corporation or other entity if the Commission knows or has reason to

believe it is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government." The NRC's regulation, 10 CFR 50.38, contains language to implement this prohibition.

According to the application, the direct license transfer application provides that Holtec, and its subsidiaries, are not owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government. Holtec is privately held and controlled by its Board of Directors, all of whom are U.S. citizens. The Directors are appointed by Holtec's owners, who are trust companies organized in the State of Florida that are controlled by U.S. citizens who control the private equity funds that own holdings. Holtec Power, Nuclear Asset Management Company, LLC (NAMCo), OCEP, and HDI are all directly or indirectly controlled by Holtec, and all directors and executive committee members are U.S. citizens. CDI is jointly owned by Holtec (majority) and SNC-Lavalin, a Canadian-based company. CDI's role is defined as the Decommissioning General Contractor and is not the licensed owner or operator of Oyster Creek, nor will CDI have direct access to the Oyster Creek NDT. While there is no prohibition against foreign-owned companies performing licensed activities, the staff considered the implications, but found no reason to believe that CDI's role in the decommissioning of Oyster Creek would impact control or domination of Holtec or its subsidiaries.

Based on this information and independent open-source analysis, the staff finds that the transfer of ownership and decommissioning authority of the facility to OCEP and HDI as proposed in the application does not raise any issues related to FOCD within the meaning of the AEA and NRC regulations. In light of the above and pursuant to Sections 103d and 104d of the AEA and 10 CFR 50.38, the staff concludes that it does not know, or have reason to believe, that Holtec or its subsidiaries, including OCEP and HDI, will be owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government, as a result of the license transfer.

8.0 NUCLEAR INSURANCE AND INDEMNITY

Pursuant to the requirements of the Price-Anderson Act (Section 170 of the AEA) and the NRC's implementing regulations in 10 CFR Part 140, the current indemnity agreement must be modified to reflect that, after the proposed license transfers take effect, OCEP (licensed owner) and HDI (licensed operator for decommissioning) will be the sole licensees for Oyster Creek for purposes of decommissioning the site. Consistent with NRC practice, the staff will require OCEP and HDI to provide and maintain onsite property insurance as specified in 10 CFR 50.54(w), "Conditions of licenses." OCEP and HDI are also required to provide evidence that they have obtained the appropriate amount of insurance in accordance with 10 CFR 140.11(a)(4), which will be effective concurrent with the date of the license transfers and amended indemnity agreement. Therefore, the order approving the transfer will be conditioned as follows:

> "Prior to the closing of the license transfer, OCEP and HDI shall provide the Directors of NRC's Office of Nuclear Material Safety and Safeguards (NMSS) and Office of Nuclear Reactor Regulation (NRR) satisfactory documentary evidence that they have obtained the appropriate amount of insurance required of a licensee under 10 CFR 140.11(a)(4) and 10 CFR 50.54(w) of the Commission's regulations, consistent with the exemptions issued to Oyster Creek on June 12, 2019."

Based on the above, the staff concludes that the proposed license transfer, as conditioned, satisfies the nuclear insurance and indemnity requirements of 10 CFR Part 140 and 10 CFR Part 50.

Financial Qualifications Conclusion

Based on the foregoing, and subject to the conditions described herein, the staff concludes that OCEP and HDI are financially qualified to hold the license for the Oyster Creek and the general license for the Oyster Creek ISFSI, as described in the application, and engage in the proposed maintenance and decommissioning activities associated with the Oyster Creek site. The staff has concluded, based on the considerations discussed above, that: (1) the proposed transferees are qualified to be the holders of license DPR-16 and (2) the transfer of the license is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission pursuant thereto.

Additionally, the staff finds that the Applicants have satisfied the NRC's decommissioning funding assurance requirements and the applicable onsite and offsite insurance requirements as conditioned. Further, the staff finds that the Applicants are not owned, controlled, or dominated by a foreign entity.

9.0 TECHNICAL EVALUATION

9.1 Management and Technical Support Organization

Oyster Creek *Environmental Protection, LLC and Holtec Decommissioning International, LLC*

HDI and OCEP will be required to comply with all the requirements of the Oyster Creek current NRC licenses and applicable NRC regulations upon transfer of the licenses. As stated in the license transfer application, Holtec International is the ultimate parent company of OCEP and HDI. Holtec Power, Inc. (Holtec Power) is a direct, wholly-owned subsidiary of Holtec International. OCEP is a direct, wholly-owned subsidiary of NAMCo, which, in turn, is a direct, wholly-owned subsidiary of Holtec Power. HDI is also a direct, wholly-owned subsidiary of Holtec Power. As stated in the application, following NRC approval, OCEP will purchase Oyster Creek, including the ISFSI, pursuant to the terms of a PSA among the Applicants. OCEP will own the facility, as well as its associated assets and title to spent nuclear fuel. Upon closing the proposed transaction, HDI will assume licensed responsibility as the decommissioning operator of Oyster Creek, and OCEP will assume licensed responsibility as the owner of the site. OCEP will enter into a decommissioning operator services agreement with HDI, which will provide for HDI to act as OCEP's agent and for OCEP to pay HDI's costs for post-shutdown operations, including decommissioning, spent fuel management, and site restoration costs. HDI's licensed activities will involve possessing and disposing of radioactive material, maintaining the facility in a safe condition (including handling, storing, controlling, and protecting the spent fuel), decommissioning and decontaminating the facility, and maintaining the ISFSI until it can be decommissioned.

The Applicants further stated, in Sections II and V.C of Enclosure 1 to the August 31, 2018, application (ADAMS Accession No. ML18243A489), that HDI will contract with CDI, a company jointly formed and owned by Holtec and SNC-Lavalin, as the decommissioning general contractor, subject to HDI's direct control and oversight as the decommissioning licensed operator. HDI will become Oyster Creek's licensed operator for decommissioning, and CDI will perform day-to-day licensed activities at the site, including decommissioning activities, pursuant

to the Decommissioning General Contractor Agreement between HDI and CDI, subject to HDI's direct oversight and control as the decommissioning licensed operator.

The application further specified that CDI will subcontract with industry vendors who have "demonstrated expertise in dismantlement and decommissioning in the nuclear field." HDI and CDI will select subcontractors using industry vendor evaluation and selection vetting process, with key criteria for selection that include technical capability to perform tasks, safety record, prior record of adherence to quality, and history of adverse NRC notices, such as Notices of Violation, Confirmatory Action Letters, etc.

HDI's responsibilities as the licensed operator were described in Section V.B of the application, to include the following:

- Meeting all duties and obligations of the decommissioning operator licensee, including continuing compliance with the ISFSI Certificate of Compliance, licensing basis, and regulatory commitments and requirements;
- Possession and disposition of radioactive material;
- Maintaining the facility in a safe condition, including the storage, control, and protection of the spent fuel in the pool and on the ISFSI, until the ISFSI is decommissioned;
- Establishing and implementing processes to ensure compliance with the licenses and NRC regulations, and retaining decision-making authority for any issues related to compliance with the licenses and NRC regulations;
- Overseeing the development and submittal of licensing actions required to support ongoing decommissioning activities;
- Making necessary modification to the emergency preparedness and security plans and responses to NRC orders regarding security;
- Performing the functions necessary to fulfill the quality assurance requirements of the Oyster Creek Technical Specifications and as specified in the Oyster Creek Quality Assurance Program Manual (QAPM) in place at the time of license transfer; and
- Providing oversight of CDI, including oversight of quality assurance, safety, and security.

The application described HDI as being structured in a manner that is similar to the corporate organization that exists in many current nuclear industry utilities with a fleet of operating units. The on-site HDI position of Oyster Creek Site Vice President is planned to be filled with an Oyster Creek incumbent senior manager.

The Applicants provided a combined organizational chart of the Oyster Creek organization in Figure V-1, depicting the relationships between HDI as the decommissioning licensed operator and CDI and the decommissioning general contractor. Further, information about the roles and responsibilities of HDI and CDI senior management were provided in Sections V.B and V.C of Enclosure 1 to the August 31, 2018 letter (ADAMS Accession No. ML18243A489), respectively. The planned HDI senior management organization will be composed of Holtec personnel and will include the following:

- The HDI President and Chief Nuclear Officer (CNO) will report directly to Holtec Executive Committee. The HDI President and CNO will be responsible for overseeing the safety, operation, and decommissioning of Oyster Creek.

- The HDI Vice President for Quality Assurance and Nuclear Oversight will report to the HDI President and CNO and will be responsible for providing quality assurance oversight

for Oyster Creek, including quality assurance oversight for the movement of fuel and the transportation of radioactive waste.

- The HDI Senior Vice President and Chief Operating Officer (COO) will report to the HDI President and CNO and will be responsible for providing oversight of the decommissioning activities performed by CDI, including fuel management, security, and emergency preparedness.

- The HDI Oyster Creek Site Vice President will report to the HDI Senior Vice President and COO and will be responsible for providing day-to-day onsite leadership and direction of safe decommissioning activities at the site. In addition, the HDI Oyster Creek Site Vice President will be responsible for assuring compliance with the licenses, including the Technical Specifications, ISFSI Certificate of Compliance, and any other regulatory requirements and commitments.

- The HDI Vice President for Licensing will report to the HDI Senior Vice President and COO and will be responsible for providing licensing oversight for the decommissioning of Oyster Creek.

- The HDI Vice President for Technical Support will report to the HDI Senior Vice President and COO and will be responsible for providing technical support in the areas of health and safety, the environment, radiation protection, and decommissioning improvements at Oyster Creek.

- The CDI Oyster Creek Decommissioning General Manager will report to the HDI Oyster Creek Site Vice President and will be leading the CDI team and will maintain responsibility for overall management, performance, nuclear safety, quality assurance, and employee safety. The CDI Oyster Creek Decommissioning General Manager will also report to the CDI Vice President for Corporate Operations, who, in turn, reports directly to the CDI President. The following organizations and their respective managers will be reporting to the CDI Oyster Creek Decommissioning General Manager: Decommissioning Deputy General Manager, Regulatory Affairs Manager, Spent Fuel Manager, Radiation Protection Manager, Waste Manager, Decommissioning Projects Manager, and Project Controls Manager. In addition, the incumbent Exelon Generation Oyster Creek Decommissioning Organization personnel at the time of license transfer who accept offers of employment will be integrated into the CDI site organization. These personnel will continue to be located at Oyster Creek, and will include staff from the Plant Operations, Emergency Planning, and Security organizations, with their roles and responsibilities based largely on their pre-transfer role and responsibilities. Incumbent staffing levels will be based on the permanent shutdown and defueled status of Oyster Creek immediately prior to license transfer.

The Applicants further stated that CDI will support HDI's responsibility to maintain the facility in compliance with the licenses and NRC regulations by performing licensed activities and decommissioning safely and securely. HDI will retain ultimate decision-making authority and will provide direct governance and oversight of CDI's performance, thereby fulfilling its licensed responsibilities as the decommissioning licensed operator. HDI will be managed by Holtec senior staff to provide the requisite managerial capabilities and decision-making authority within the licensed organization, while CDI will be staffed with a combination of Holtec and Atkins personnel who have commercial nuclear experience, including experience in spent fuel handling

and decommissioning. As of the transaction closing, CDI will become the employer of Exelon Generation employees in the Oyster Creek Decommissioning Organization, except for an incumbent senior manager at Oyster Creek, who will be employed by HDI.

As stated in Sections V.C, V.D, and VIII. E of Enclosure 1 to the August 31, 2018, letter (ADAMS Accession No. ML18243A489), CDI will perform the day-to-day activities at the site to maintain compliance with the licenses and NRC regulations, subject to HDI's direct oversight and control as the licensed operator. Exelon Generation will transfer to OCEP the assets related to Oyster Creek that will be needed to maintain Oyster Creek and the site in accordance with NRC requirements and the facility licenses. These assets will include, in addition to the structures and equipment, the necessary books, records, safety and maintenance manuals, and engineering construction documents. HDI plans to adopt the current NRC-approved Exelon Generation policies, programs, procedures, and work instructions applicable to Oyster Creek, and HDI and CDI will continue to work in accordance with those documents following the post-license transfer. The existing Oyster Creek programs and procedures at the time of transfer, including the emergency plan, physical security and cyber security plans, fire protection program, radiological protection, certified fuel handler training, and quality assurance (QA) program will also be implemented by HDI and CDI, post-license transfer. Upon closing of the transaction, HDI will assume authority and responsibility for the functions necessary to fulfill the QA requirements of the Oyster Creek Technical Specifications and as specified in the Oyster Creek QAPM in place at the time of license transfer. The Oyster Creek QAPM will be added as an appendix to the Holtec QA Program and specified as applicable to the Oyster Creek site.

Strategic Partner Experience and Expertise

According to the application, HDI will draw on the experience and expertise of its parent company, Holtec, and its contractor CDI. Under HDI's direct oversight and control, CDI will perform the day-to-day licensed activities at the site, including decommissioning the plant, pursuant to a Decommissioning General Contractor Agreement between HDI and CDI. CDI will be staffed with a combination of Holtec and SNC-Lavalin personnel who have commercial nuclear experience, including experience in spent fuel handling and decommissioning. In addition to employees transferred from Holtec and SNC-Lavalin, CDI staffing will include Exelon Generation Oyster Creek Decommissioning Organization incumbent staff who, at the time of the license transfer, will be integrated into the CDI decommissioning organization, in a manner consistent with their experience and previous positions at Oyster Creek.

The experience and expertise of HDI and each of its strategic partners is briefly described below:

HDI is an indirect, wholly-owned subsidiary of Holtec. The senior management of HDI is composed of Holtec personnel. HDI is structured to serve as a fully resourced organization to directly oversee and manage licensed decommissioning operations and the dismantlement of a nuclear power plant that has ceased operation. HDI has expertise to oversee all licensed activities following reactor defueling, including the transfer of spent fuel from the spent fuel pool to the ISFSI, security, and emergency preparedness.

Holtec has extensive experience in designing, manufacturing, and installing capital equipment, as well as providing services to operating commercial power plants. Holtec also possesses in-house capabilities to design, engineer, analyze, construct, and deploy spent fuel. Holtec possesses both technical resources and experience with nuclear decommissioning, spent fuel

handling equipment, transport of nuclear fuel, and wet and dry spent fuel storage systems and components.

CDI is a company jointly owned by HDI and Kentz USA Inc., an SNC-Lavalin subsidiary. CDI is majority owned by Holtec. As stated in the application, CDI will be staffed with a combination of Holtec and SNC-Lavalin personnel who have commercial nuclear experience, including experience in spent fuel handling and decommissioning, and enhanced by the addition of incumbents from the nuclear site owner who will transition following license transfer to HDI. CDI personnel will also include Atkins personnel who have decommissioning expertise and experience.

SNC-Lavalin, one of CDI's joint owners, is an engineering and construction company. SNC-Lavalin is also the current owner and the original equipment manufacturer of CANDU reactor technology. SNC-Lavalin acquired Atkins in July 2017, which then became a wholly-owned subsidiary of SNC-Lavalin. Atkins is a design, engineering, and project management consultancy company, based in the United Kingdom (U.K.). Atkins has been involved in the nuclear clean-up, decommissioning, and environmental remediation of nuclear waste storage sites activities since the late 1980s, working with Sellafield Ltd (formerly British Nuclear Fuels Limited (BNFL)) and managing the fleet of 22 Magnox reactors, through operation and into decommissioning in the U.K. In addition, in 2016, Atkins acquired the Energy*Solutions*' Projects, Products, and Technology (PP&T) division, which was responsible for decommissioning of the Zion Nuclear Generating Station. In addition, BNFL, which is now owned by Atkins through its acquisition of Energy*Solutions* PP&T, had a significant role in the decommissioning of Big Rock Point, including the removal of the large components and reactor vessel.

Conclusion

Based on its review of the application for license transfer, the staff finds that the Applicants provided reasonable assurance that the requirements of 10 CFR 50.34(b)(7) and 10 CFR 50.80 regarding the technical qualifications of HDI to engage in the proposed activities have been met. In addition, the staff finds that HDI are technically qualified to be the holder of the license, and that the transfer of the license is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission. Accordingly, the staff concludes that the proposed HDI management and technical support organization will adequately support the proposed maintenance and decommissioning activities at Oyster Creek.

9.2 Onsite Organization

As stated in the application, CDI will establish a site decommissioning organization. CDI plans to employ the Exelon Generation Oyster Creek Decommissioning Organization site personnel remaining at the site at the time of the transaction closing, except for one incumbent senior manager, who will become an HDI employee as the Site Vice President in charge of the site-based organization.

The application stated that staffing levels at the time of transfer will be fully compliant with the requirements of facility licenses and NRC regulations. HDI will ensure that vacated positions previously filled by incumbent employees are backfilled with qualified personnel, subject to a determination of the need to fill the position. In all cases, the individuals will be qualified to Oyster Creek's programs and procedures.

The staffing and qualification requirements for the current operating organization at Oyster Creek were previously found to be acceptable, as approved in Amendment No. 295 to Renewed Facility Operating License No. DPR-16 and the associated defueled technical specifications, consistent with the permanent cessation of operations and permanent removal of fuel from the reactor vessel. These requirements detailed, among others, the responsibilities of a Plant Manager and a Shift Manager and stipulated that the minimum shift crew composition include at least one Shift Manager, who must be a Certified Fuel Handler, and one Non-Certified Operator. In addition, the facility staff qualifications are required to be maintained as stated in Section 6.3 of the Technical Specifications. The proposed changes to the license as described in Enclosure 1, Attachment A to the letter do not affect the staffing or qualifications requirements as approved in Amendment No. 295.

In Enclosure 3 to the letter, the Applicants provided resumes of key personnel with responsibilities of regulatory significance, including, among others, those of the HDI President and CNO, HDI Senior Vice President and COO, HDI Vice President for Quality Assurance and Nuclear Oversight, HDI Vice President for Licensing, HDI Vice President for Technical Support, and CDI Oyster Creek Decommissioning General Manager. The resumes provided information regarding the experience of individuals who will occupy the aforementioned-key positions in the areas of spent fuel management, decommissioning, nuclear safety, licensing and regulatory affairs, engineering and operations, and quality assurance.

Conclusion

Based on its evaluation, the staff concludes that the onsite organization will adequately support the proposed maintenance and decommissioning activities at Oyster Creek in accordance with 10 CFR 50.34(b)(7) that requires Applicants to provide the technical qualifications to engage in the proposed activities, and 10 CFR 50.80(c) that requires the proposed license transferee to be qualified to be the holder of the license and is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission.

9.3 Technical Qualifications Conclusions

The Applicants have described the management and technical support organization, as well as the onsite operating organization, that would be responsible for the maintenance and decommissioning of Oyster Creek after the proposed transfer of licensed authority to HDI. Based on its evaluation as described above, the staff concludes that: (1) HDI will have an acceptable management organization; (2) HDI will retain an onsite organization capable of safely conducting decommissioning activities; and (3) HDI will have the technically qualified resources and experience to support the safe maintenance and decommissioning of the Oyster Creek site after the transfer of licensed authority from Exelon to HDI. The staff also determined that the Applicants provided reasonable assurance that the relevant requirements of 10 CFR 50.34(b)(7) and 10 CFR 50.80 to engage in the proposed activities have been met. Accordingly, in light of the foregoing evaluation, the staff finds that HDI is technically qualified to hold the Oyster Creek License No. DPR-16 as proposed.

10.0 CONFORMING LICENSE AMENDMENT

10.1 Conforming Amendment

The Applicants requested a conforming amendment to License No. DPR-16 for Oyster Creek. No physical or operational changes to the facility were requested beyond those captured in the

HDI revised PSDAR. The proposed conforming amendment only reflects the proposed license transfer action. The amendment involves no safety question and is administrative in nature. Accordingly, the proposed amendment is acceptable.

10.2 State Consultation

In accordance with the Commission's regulations, the New Jersey State official was notified of the proposed issuance of the amendment on May 16, 2019. The State official responded on May 31, 2019 (ADAMS Accession No. ML19154A058) stating:

> "The Bureau of Nuclear Engineering (BNE) reviewed the License Transfer Application (LTA) outlining the terms and conditions of the license transfer from Exelon to OCEP as the licensed owner and to HDI as the licensed operator for decommissioning. BNE staff met with the Decommissioning Team from both Exelon and Holtec to review certain aspects of the LTA and to ask clarifying questions regarding the transfer of the license. All BNE comments/concerns were discussed and satisfactorily addressed during the meeting. Additionally, the New Jersey Department of Environmental Protection (NJDEP) signed an Administrative Consent Order (ACO) agreement with Exelon outlining specific emergency preparedness requirements and commitments that have been addressed in the LTA.
>
> Based on the outcome of the meeting discussions and the ACO commitments, the NJDEP has no comments or concerns with the issuance of this Amendment."

10.3 Conforming Amendment Conclusion

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by the proposed action; (2) there is reasonable assurance that such activities will be conducted in compliance with the Commission's regulations; and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

11.0 <u>ENVIRONMENTAL CONSIDERATION</u>

The subject application is for approval of a transfer of a license issued by the NRC and an associated conforming amendment required to reflect the approval of the transfer. Accordingly, the actions involved meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(21). Pursuant to 10 CFR 51.22(b), no EIS or environmental assessment need be prepared in connection with the approval of the transfer application and conforming license amendment.

12.0 <u>PUBLIC COMMENT</u>

The NRC's notice of consideration of the approval of transfer of license and conforming amendment was published in the in the *Federal Register* on October 19, 2018 (83 FR 53119) and included an opportunity to comment, request a hearing, and petition for leave to intervene. The comment period was re-opened on December 10, 2018 (83 FR 63544) for an additional 30-days.

Comments received in response to the *Federal Register* notices can be found at ADAMS Accession Numbers ML18302A223, ML18324A638, ML18324A776, ML18362A095,

ML19003A242, ML19004A075, ML19009A326, and ML19010A308. Two hearing requests were also received. These requests can be found at ADAMS Accession Numbers ML18306A866, ML18312A251.

On June 18, 2019, the Commission issued a Memorandum and Order (CLI-19-06) denying both hearing requests and terminating the adjudicatory proceeding (ADAMS Accession No. ML19169A106). In CLI-19-06, the Commission referred the following documents to the staff for consideration as comments on the Oyster Creek license transfer application:

1) Sierra Club New Jersey Chapter Comments and Request for Public Hearing (ADAMS Accession No. ML18306A866)

2) Comments Received from Paul Dressler representing the Concerned Citizens for Lacey Coalition, and other interested individuals (ADAMS Accession No. ML19161A084)

The themes of the questions and comments received were as follows:

1) Concerns about the responsibility for any decommissioning fund shortfalls and the financial integrity or technical qualifications of Holtec and its partners, including the impact of a potential loss of tax breaks

2) Use of the site after decommissioning

3) Concerns about continued storage of spent fuel after decommissioning, transportation of spent fuel and radioactive waste, and where spent fuel will go once removed from the site

4) Concerns with Holtec new dry cask canister design and faster transfer of fuel from the fuel pool to the dry cask canister

5) Concerns that support for the license transfer is partially based on proprietary information or incomplete cost information, and that the work will have proper oversight

6) Concern with Holtec's partners previous legal issues (bankruptcy)

7) Concerns about the reduction of emergency planning and security

8) Corrosion in the drywell

9) Concerns that an EIS must be completed before the license transfer can be completed

10) Particular concerns (ADAMS Accession Nos. ML18324A638 and ML18324A776) referencing charges against SNC-Lavalin for corruption, fraud, and bribery relating to business operations in Libya

11) Request that a public meeting be held before the NRC approves the license transfer

The staff reviewed the written public comments received during the open comment period; the comments from the State of New Jersey (ADAMS Accession No. ML19114A495); and the comments referred to the staff in CLI-19-06 (ADAMS Accession Nos. ML18306A866 and ML19161A084), and considered them in the review process. The themes of the questions and

comments that were in the scope of the NRC staff's review, such as concerns about decommissioning fund shortfalls and the financial integrity and/or the financial and technical qualifications of Holtec and its partners, to include proprietary information or incomplete cost information, are addressed below and in this safety evaluation of the license transfer application. The themes of questions and comments 2 through 4, 6 through 8, and portions of comment 5 mentioned above, were beyond the scope of the NRC staff's review of this license transfer application.

Regarding question/comment theme 1 above related to the potential loss of tax breaks, the staff found that there is no apparent nexus between the issue and the staff's review of the license transfer application. In the Oyster Creek license transfer application, the Applicants are relying on the existing decommissioning trust funds rather than internal resources to fund expenses associated with the project. Therefore, the staff determined that the potential loss of a tax break, including the resulting effect on the Applicants' financial resources, does not impact the staff's review of the Applicants' financial qualifications or decommissioning funding assurance with respect to this license transfer application.

Regarding question/comment theme 9 above, the subject application is for approval of a transfer of a license issued by the NRC and an associated conforming amendment required to reflect the approval of the transfer. Accordingly, the staff has determined that the license transfer and conforming amendment meet the eligibility criteria for the categorical exclusion set forth in 10 CFR 51.22(c)(21). Therefore, pursuant to 10 CFR 51.22(b), no EIS or environmental assessment need be prepared in connection with the approval of the transfer application and conforming license amendment.

Regarding question/theme 10 above, in accordance with 10 CFR 50.80(b)(1), the focus of the staff's review for this license transfer application was on the financial and technical qualifications of the proposed transferees, OCEP and HDI. Upon NRC approval of the license transfer and conforming amendment, OCEP would become the owner of Oyster Creek and HDI would be the decommissioning operator. In addition, as discussed in this safety evaluation, the staff has determined that the transfer of the Oyster Creek licenses and issuance of the conforming amendment will not be inimical to the common defense and security.

Regarding question/theme 11 above, the staff typically does not hold public meetings on license transfer applications, and there is no requirement to hold such a public meeting. However, the staff is required to hold public meetings on the Post Shutdown Decommissioning Activities Report and the License Termination Plan per 10 CFR 50.82(a)(4)(ii) and 10 CFR 50.82(a)(9)(iii), respectively. On July 17, 2018, the staff held a public meeting in Forked River, New Jersey to request for comments on the 2018 PSDAR, including the DCE. In accordance with 10 CFR 50.82(a)(9)(iii), the staff will schedule a public meeting upon receipt of the license termination plan.

13.0 CONCLUSION

Based on the foregoing, and subject to the conditions described herein, the staff concludes that HDI and OCEP are financially and technically qualified to hold the license for the Oyster Creek and the general license for the Oyster Creek ISFSI, as described in the application, and engage in the proposed maintenance and decommissioning activities associated with the Oyster Creek site. The staff has concluded, based on the considerations discussed above, that: (1) the proposed transferees are qualified to be the direct holders of license DPR-16 and (2) the direct

transfer of the license is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission pursuant thereto.

Additionally, the staff finds that the Applicants have satisfied the NRC's decommissioning funding assurance requirements and the applicable onsite and offsite insurance requirements as conditioned. Further, the staff finds that the Applicants are not owned, controlled, or dominated by a foreign entity.

The proposed license transfer will be consistent with the requirements of the AEA, NRC regulations, and regulatory guidance. The transfer of the Licenses will not be inimical to the common defense and security and does not involve foreign ownership, control, or domination.

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Date: June 20, 2019

Attachment 1 – NRC's Independent Cash Flow Analysis

Cash Flow Analysis
Oyster Creek Nuclear Generating Station
Nuclear Decommissioning Trust
(millions of 2018$)

Year	BOY NDT Balance	License Termination Cost	Spent Fuel Management Cost	Site Restoration Cost	Total Costs	NDT Earnings (2% RRR)	EOY NDT Balance
2019	$848	$95	$2	$3	$100	$15	$763
2020	$763	$89	$64	$17	$170	$12	$605
2021	$605	$76	$4	$7	$87	$10	$528
2022	$528	$81	$12		$93	$9	$444
2023	$444	$121	$16		$137	$6	$313
2024	$313	$134	$3	$13	$150	$3	$166
2025	$166	$10	$9	$1	$20	$3	$149
2026	$149		$8		$8	$3	$144
2027	$144		$8		$8	$3	$139
2028	$139		$8		$8	$3	$133
2029	$133		$8		$8	$3	$128
2030	$128		$8		$8	$2	$122
2031	$122		$8		$8	$2	$117
2032	$117		$8		$8	$2	$111
2033	$111	$9	$27		$36	$1	$76
2034	$76	$2	$27		$29	$1	$48
2035	$48	$1	$8	$1	$10	$1	$39
	Totals	$618	$228	$42	$888		

Notes:

1. The 2019 beginning of year (BOY) NDT balance reflects the fund value post-closure of asset sale and includes deductions for estimated Exelon pre-closure costs. The 2019 costs include HDI estimated pre- and post-closure costs.
2. Assumes no credit for DOE reimbursements.
3. ISFSI decommissioning costs ($3.9 million) included in above cash flow analysis.

ENTERGY NUCLEAR GENERATION COMPANY *

And ENTERGY NUCLEAR OPERATIONS, INC.

(PILGRIM NUCLEAR POWER STATION)

DOCKET NO. 50-293

RENEWED FACILITY OPERATING LICENSE

Renewed License No. DPR-35

The Nuclear Regulatory Commission (the Commission) has found that:

a. Except as stated in condition 5, construction of the Pilgrim Nuclear Power Station (the facility) has been substantially completed in conformity with the application, as amended, the Provisional Construction Permit No. CPPR-49, the provisions of the Atomic Energy Act of 1954, as amended (the Act), and the rules and regulations of the Commission as set forth in Title 10, Chapter 1, CFR; and

b. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission; and

c. There is reasonable assurance (i) that the activities authorized by the renewed operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission; and

d. The Entergy Nuclear Generation Company (Entergy Nuclear) is financially qualified and Entergy Nuclear Operations, Inc. (ENO) is technically and financially qualified to engage in the activities authorized by this renewed operating license, in accordance with the rules and regulations of the Commission; and

e. Entergy Nuclear and ENO have satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements" of the Commission's regulations; and

f. The issuance of this renewed operating license will not be inimical to the common defense and security or to the health and safety of the public; and

g. After weighing the environmental, economic, technical, and other benefits of the facility against environmental costs and considering available alternatives, the issuance of this renewed operating license (subject to the condition for protection of the environment set forth herein) is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements of said regulations have been satisfied; and

h. Actions have been identified and have been or will be taken with respect to (1) managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under

* The Nuclear Regulatory Commission approved the transfer of the license from Boston Edison Company to Entergy Nuclear Generation Company on April 29, 1999.

10 CFR 54.21(a)(1); and (2) time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c), such that there is reasonable assurance that the activities authorized by the renewed operating license will continue to be conducted in accordance with the current licensing basis, as defined in 10 CFR 54.3, for the facility, and that any changes made to the facility's current licensing basis in order to comply with 10 CFR 54.29(a) are in accordance with the Act and the Commission's regulations.

Facility Operating License No. DPR-35, dated June 8, 1972, issued to the Boston Edison Company (Boston Edison) is hereby amended in its entirety, pursuant to an Initial Decision dated September 13, 1972, by the Atomic Safety and Licensing Board, to read as follows:

1. This renewed operating license applies to the Pilgrim Nuclear Power Station, a single cycle, forced circulation, boiling water nuclear reactor and associated electric generating equipment (the facility), owned by Entergy Nuclear and operated by ENO. The facility is located on the western shore of Cape Cod Bay in the town of Plymouth on the Entergy Nuclear site in Plymouth County, Massachusetts, and is described in the "Final Safety Analysis Report," as supplemented and amended.

2. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses Entergy Nuclear:

    A. Pursuant to the Section 104b of the Atomic Energy Act of 1954, as amended (the Act) and 10 CFR Part 50, "Licensing of Production and Utilization Facilities," a) Entergy Nuclear to possess and use and b) ENO to possess, use, and operate the facility as a utilization facility at the designated location on the Pilgrim site;

    B. ENO, pursuant to the Act and 10 CFR 70, to receive, possess, and use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report, as supplemented and amended;

    C. ENO, pursuant to the Act and 10 CFR Parts 30, 40 and 70 to receive, possess and use at any time any byproduct, source or special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

    D. ENO, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

    E. ENO, pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

3. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations; 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50 and Section 70.32 of 10 CFR Part 70; and is subject to all applicable

provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

A. Maximum Power Level

ENO is authorized to operate the facility at steady state power levels not to exceed 2028 megawatts thermal.

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 247, are hereby incorporated in the renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

C. Records

ENO shall keep facility operating records in accordance with the requirements of the Technical Specifications.

D. Equalizer Valve Restriction - DELETED

E. Recirculation Loop Inoperable - DELETED

F. Fire Protection

ENO shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the facility and as approved in the SER dated December 21, 1978 as supplemented subject to the following provision:

ENO may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

G. Physical Protection

The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contain Safeguards Information protected under 10 CFR 73.21, is entitled: "Pilgrim Nuclear Power Station Physical Security, Training and Qualification, and Safeguards Contingency Plan, Revision 0" submitted by letter dated October 13, 2004, as supplemented by letter dated May 15, 2006.

The licensee shall fully implement and maintain in effect all provisions of the Commission-approved cyber security plan (CSP), including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The licensee's CSP was approved by License Amendment No. 236, as supplemented by changes approved by: Amendment Nos. 238, 241, 244, and 247.

H. Post-Accident Sampling System. NUREG-0737, Item II.B.3. and Containment Atmospheric Monitoring System, NUREG-0737. Item II.F.1(6)

The licensee shall complete the installation of a post-accident sampling system and a containment atmospheric monitoring system as soon as practicable, but no later than June 30, 1985.

I. Additional Conditions

The Additional Conditions contained in Appendix B, as revised through Amendment No. 177, are hereby incorporated into this renewed operating license. ENO shall operate the facility in accordance with the Additional Conditions.

J. Conditions Related to the Sale and Transfer

(1) For purposes of ensuring public health and safety, Entergy Nuclear shall provide decommissioning funding assurance of no less than $396 million, after payment of any taxes, in the decommissioning trust fund for Pilgrim upon the transfer of the Pilgrim licenses to Entergy Nuclear.

(2) Entergy Nuclear shall maintain the decommissioning trust funds in accordance with the Order, the related Safety Evaluation dated April 29, 1999, and the related application for approval of the transfer.

(3) Entergy Nuclear shall provide a Provisional Trust fund in the amount of $70 million, after payment of any taxes, in the Provisional Trust for Pilgrim upon the transfer of the Pilgrim licenses to Entergy Nuclear. The Provisional Trust shall be established and maintained in conformance with the representations made in the application for approval of the transfer.

(4) Entergy Nuclear shall have access to a contingency fund of not less than fifty million dollars ($50m) for payment, if needed, of Pilgrim operating and maintenance expenses, the cost to transition to decommissioning status in the event of a decision to permanently shut down the unit, and decommissioning costs. Entergy Nuclear will take all necessary steps to ensure that access to these funds will remain available until the full amount has been exhausted for the purposes described above. Entergy Nuclear shall inform the Director, Office of Nuclear Regulation, in writing, at such time that it utilizes any of these contingency funds. This provision does not affect the NRC's authority to assure that adequate funds will remain available in the plant's separate decommissioning fund(s), which Entergy Nuclear shall maintain in accordance with NRC regulations. Once the plant has been placed in a safe-shutdown condition following a decision to decommission, Entergy Nuclear will use any remainder of the $50m contingency fund that has not been used to safely operate and maintain the plant to support the safe and prompt decommissioning of the plant, to the extent such funds are needed for safe and prompt decommissioning.

(5) The Decommissioning Trust agreement(s) shall be in a form which is acceptable to the NRC and shall provide, in addition to any other clauses, that:

a) Investments in the securities or other obligations of Entergy Nuclear, Entergy Corporation, their affiliates, subsidiaries or associates, or their successors or assigns shall be prohibited. In addition, except for investments tied to market indexes or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants is prohibited.

b) The Director, Office of Nuclear Reactor Regulation, shall be given 30 days prior written notice of any material amendment to the trust agreement(s).

K. Mitigation Strategy License Condition

Develop and maintain strategies for addressing large fires and explosions and that include the following key areas:

(a) Fire fighting response strategy with the following elements:
1. Pre-defined coordinated fire response strategy and guidance
2. Assessment of mutual aid fire fighting assets
3. Designated staging areas for equipment and materials
4. Command and control
5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:
1. Protection and use of personnel assets
2. Communications
3. Minimizing fire spread
4. Procedures for implementing integrated fire response strategy
5. Identification of readily-available pre-staged equipment
6. Training on integrated fire response strategy
7. Spent fuel pool mitigation measures

(c) Actions to minimize release to include consideration of:
1. Water spray scrubbing
2. Dose to onsite responders

L. The licensee shall implement and maintain all Actions required by Attachment 2 to NRC Order EA-06-137, issued June 20, 2006, except the last action that requires incorporation of the strategies into the site security plan, contingency plan, emergency plan and/or guard training and qualification plan, as appropriate.

M. Upon Implementation of Amendment No. 231 adopting TSTF-448, Revision 3, the determination of control room envelope (CRE) unfiltered air inleakage required by SR 4.7.6.2.e in accordance with TS 5.5.8.c.(i), the assessment of CRE habitability as required by Specification 5.5.8.c.(ii), and the measurement

of CRE pressure as required by Specification 5.5.8.d shall be considered met as follows:

(a) The first performance of SR 4.7.2.6.5.e in accordance with Specification 5.5.8.c.(i) shall be within the specified frequency of 6 years, plus the 18-month allowance as defined by SURVEILLANCE INTERVAL measured from December 5, 2005, the date of the most recent successful tracer gas test, as stated in Entergy's letter "Follow-Up Response to NRC Generic Letter 2003-01" (EN0 2.06.019), dated March 20, 2006, or within 18 months if the time period since the most recent successful tracer gas test is greater than 6 years.

(b) The first performance of the periodic assessment of CRE habitability Specification 5.5.8.c.(ii) shall be within 3 years, plus the 9-month allowance of SURVEILLANCE INTERVAL as measured from December 5, 2005, the date of the most recent successful tracer gas test, as stated in Entergy's letter "Follow-Up Response to NRC Generic Letter 2003-01" (EN0 2.06.019), dated March 20, 2006, or within 9 months if the time period since the most recent successful tracer gas test is greater than 3 years.

(c) The first performance of the periodic measurement of CRE pressure, Specification 5.5.8.d shall be within 24 months, plus the 180-day allowance of the SURVEILLANCE INTERVAL as measured from the date of the most recent successful pressure measurement test or within 180 days if not performed previously.

4. This license is subject to the following condition for the protection of the environment: Boston Edison shall continue, for a period of five years after initial power operation of the facility, an environmental monitoring program similar to that presently existing with the Commonwealth of Massachusetts (and described generally in Section C-III of Boston Edison's Environmental Report, Operating License Stage dated September, 1970) as a basis for determining the extent of station influence on marine resources and shall mitigate adverse effects, if any, on marine resources.

5. Boston Edison has not completed as yet construction of the Rad Waste Solidification System and the Augmented Off-Gas System. Limiting conditions concerning these systems are set forth in the Technical Specifications.

6. Pursuant to Section 105c(8) of the Act, the Commission has consulted with the Attorney General regarding the issuance of this operating license. After said consultation, the Commission has determined that the issuance of this license, subject to the conditions set forth in this subparagraph 6, in advance of consideration of and findings with respect to matters covered in Section 105c of the Act, is necessary in the public interest to avoid unnecessary delay in the operation of the facility. At the time this operating license is being issued an antitrust proceeding has not been noticed. The Commission, accordingly, has made no determination with respect to matters covered in Section 105c of the Act, including conditions, if any, which may be appropriate as a result of the outcome of any antitrust proceeding. On the basis of its findings made as a result of an antitrust proceeding, the Commission may continue this license as issued, rescind this license or amend this license to include such conditions as the Commission

deems appropriate. Boston Edison and others who may be affected hereby are accordingly on notice that the granting of this license is without prejudice to any subsequent licensing action, including the imposition of appropriate conditions, which may be taken by the Commission as a result of the outcome of any antitrust proceeding. In the course of its planning and other activities, Boston Edison will be expected to conduct itself accordingly.

7. The information in the FSAR supplement, submitted pursuant to 10 CFR 54.21(d), as supplemented by Commitments Nos. 3, 8, 9, 13, 15, 18, 19, 21, 22, 24, 25, 26, 27, 28, 30, 31, 33, 34, 35, 36, 37, 39, 40, 46, 51, and 52 of Appendix A of NUREG-1891, "Safety Evaluation Report Related to the License Renewal of Pilgrim Nuclear Power Station" dated June 2007, as supplemented, is henceforth part of the FSAR which will be updated in accordance with 10 CFR 50.71(e). In addition, the licensee shall incorporate into its FSAR the "Description of Program" from Table 3.0-1 "FSAR Supplement for Aging Management of Applicable Systems" of License Renewal Interim Staff Guidance LR-ISG-2011-05 "Ongoing Review of Operating Experience."

   The licensee may make changes to the programs and activities described in the FSAR supplement and Commitments Nos. 3, 8, 9, 13, 15, 18, 19, 21, 22, 24, 25, 26, 27, 28, 30, 31, 33, 34, 35, 36, 37, 39, 40, 46, 51, and 52 of Appendix A of NUREG-1891, as supplemented, provided the licensee evaluates such changes pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

8. The licensee's FSAR supplement submitted pursuant to 10 CFR 54.21(d), as revised during the license renewal application review process, and as supplemented by Commitments Nos. 3, 8, 9, 13, 15, 18, 19, 21, 22, 24, 25, 26, 27, 28, 30, 31, 33, 34, 35, 36, 37, 39, 40, 46, 51, and 52 of Appendix A of NUREG-1891, as supplemented, along with the FSAR description regarding consideration of operating experience for license renewal aging management programs in Condition 7 above, describes certain future programs and activities to be completed before the period of extended operation. The licensee shall complete these activities no later than June 8, 2012, and shall notify the NRC in writing when implementation of these activities is complete.

9. Capsule withdrawal schedule – For the renewed operating license term, all capsules in the reactor vessel that are removed and tested must meet the requirements of American Society for Testing and Materials (ASTM) E 185-82 to the extent practicable for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the staff prior to implementation. All capsules placed in storage must be maintained for future insertion. Any changes to storage requirements must be approved by the staff, as required by 10 CFR Part 50, Appendix H.

10. This license is effective as of the date of issuance and shall expire June 8, 2032.

FOR THE NUCLEAR REGULATORY COMMISSION

Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Attachments:
Appendix A - Technical Specifications
(Radiological)
Appendix B – Additional Conditions
Date of Issuance: May 29, 2012

APPENDIX A

TO

FACILITY OPERATING LICENSE DPR-35

TECHNICAL SPECIFICATION AND BASES

FOR

PILGRIM NUCLEAR POWER STATION

PLYMOUTH, MASSACHUSETTS

ENTERGY NUCLEAR and ENTERGY NUCLEAR OPERATIONS, INC.

Amendment No. ~~181~~, 193
MAY 05 2002

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The succeeding frequently used terms are explicitly defined so that a uniform interpretation of the specifications may be achieved.

ACTION	ACTION shall be that part of a specification which prescribes remedial measures required under designated conditions.
AUTOMATIC PRIMARY CONTAINMENT ISOLATION VALVES	Are primary containment isolation valves which receive an automatic primary containment group isolation signal.
CERTIFIED FUEL HANDLER	A CERTIFIED FUEL HANDLER is an individual who complies with the provisions of the CERTIFIED FUEL HANDLER Training and Retraining Program.
COLD CONDITION	Reactor coolant temperature equal to or less than 212°F.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. The following exceptions are not considered to be CORE ALTERATIONS: a. Movement of source range monitors, local power range monitors, intermediate range monitors, traversing incore probes, or special movable detectors (including undervessel replacement); and b. Control rod movement, provided there are no fuel assemblies in the associated core cell. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is a reload-cycle specific document that provides core operating limits for the current operating reload cycle. These cycle specific core operating limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these operating limits is addressed in individual specifications.
DESIGN POWER	DESIGN POWER means a steady state power level of 2028 thermal megawatts.
FIRE SUPPRESSION WATER SYSTEM	A FIRE SUPPRESSION WATER SYSTEM shall consist of: a water source(s); gravity tank(s) or pump(s); and distribution piping with associated sectionalizing control or isolation valves. Such valves shall include hydrant post indicator valves and the first valve ahead of the water flow alarm device on each sprinkler, hose standpipe or spray system riser.
HOT STANDBY CONDITION	HOT STANDBY CONDITION means operation with coolant temperature greater than 212°F, system pressure less than 600 psig, the main steam isolation valves closed and the mode switch in startup.
IMMEDIATE	IMMEDIATE means that the required action will be initiated as soon as practicable considering the safe operation of the unit and the importance of the required action.

INSTRUMENT CALIBRATION	An INSTRUMENT CALIBRATION means the adjustment of an instrument signal output so that it corresponds, within acceptable range and accuracy, to a known value(s) of the parameter which the instrument monitors. Calibration shall encompass the entire instrument including actuation, alarm or trip.
INSTRUMENT CHANNEL	An INSTRUMENT CHANNEL means an arrangement of a sensor and auxiliary equipment required to generate and transmit to a trip system a single trip signal related to the plant parameter monitored by that instrument channel.
INSTRUMENT CHECK	An INSTRUMENT CHECK is a determination of acceptable operability by observation of instrument behavior during operation. This determination shall include, where possible, comparison of the instrument with other independent instruments measuring the same variable.
INSTRUMENT FUNCTIONAL TEST	An INSTRUMENT FUNCTIONAL TEST means the injection of a simulated signal into the instrument primary sensor to verify the proper instrument channel response, alarm and/or initiating action..

LEAKAGE

a. Identified LEAKAGE:

l. Reactor coolant LEAKAGE into drywell collection systems, such as pump seal or valve packing leaks, that is captured and conducted to a sump or collecting tank, or

2. Reactor coolant LEAKAGE into the drywell atmosphere from sources which are both specifically located and known either not to interfere with the operation of the leakage detection systems or not to be Pressure Boundary Leakage.

b. Unidentified LEAKAGE:

Unidentified LEAKAGE shall be all reactor coolant leakage which is not Identified Leakage.

c. <u>Pressure Boundary LEAKAGE</u>

Pressure Boundary LEAKAGE shall be leakage through a non- isolable fault in a reactor coolant system component body, pipewall or vessel wall.

LIMITING CONDITIONS FOR OPERATION (LCO)

The LIMITING CONDITIONS FOR OPERATION specify the minimum acceptable levels of system performance necessary to assure safe startup and operation of the facility. When these conditions are met, the plant can be operated safely and abnormal situations can be safely controlled.

Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO.

LIMITING SAFETY SYSTEM SETTING (LSSS)	The LIMITING SAFETY SYSTEM SETTINGS are settings on instrumentation which initiate the automatic protective action at a level such that the safety limits will not be exceeded. The region between the safety limit and these settings represents margin with normal operation lying below these settings. The margin has been established so that with proper operation of the instrumentation the safety limits will never be exceeded.
LOGIC SYSTEM FUNCTIONAL TEST	A LOGIC SYSTEM FUNCTIONAL TEST means a test of all relays and contacts of a logic circuit from sensor to activated device to insure components are operable per design intent. Where practicable, action will go to completion (i.e., pumps will be started and valves opened).
MINIMUM CRITICAL POWER RATIO (MCPR)	The value of critical power ratio associated with the most limiting assembly in the reactor core. Critical Power Ratio (CPR) is the ratio of that power in a fuel assembly, which is calculated to cause some point in the assembly to experience boiling transition, to the actual assembly operating power.
MODE	The reactor MODE is that which is established by the mode-selector-switch. The MODES include:

<u>Startup MODE</u>

In this MODE the reactor protection scram trip, initiated by main steam line isolation valve closure, is bypassed when reactor pressure is less than 600 psig, the low pressure main steam line isolation valve closure trip is bypassed, the reactor protection system is energized with IRM neutron monitoring system trips and control rod withdrawal interlocks in service.

<u>Run MODE</u>

In this MODE the reactor system pressure is at or above 785 psig and the reactor protection system is energized with APRM protection and RBM interlocks in service.

<u>Shutdown MODE</u>

The reactor is in the shutdown MODE when the reactor mode switch is in the shutdown mode position and no core alterations are being performed.

a. Hot Shutdown means conditions as above with reactor coolant temperature greater than 212°F.

b. Cold Shutdown means conditions as above with reactor coolant temperature equal to or less than 212°F.

<u>Refuel MODE</u>

The reactor is in the refuel MODE when the mode switch is in the refuel mode position. When the mode switch is in the refuel position, the refueling interlocks are in service.

NON-CERTIFIED OPERATOR	A NON-CERTIFIED OPERATOR is a non-licensed operator who complies with the qualification requirements of Specification 5.3.1, but is not a CERTIFIED FUEL HANDLER.
OPERABLE - OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
OPERATING	OPERATING means that a system or component is performing its intended functions in its required manner.
OPERATING CYCLE	Interval between the end of one refueling outage and the end of the next subsequent refueling outage.
PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the Pilgrim-Specific document that provides the reactor vessel Pressure-Temperature (P-T) Curves, including heat up and cool down rates and fluence and Adjusted Reference Temperature limits for Specification 3.6.A. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.5.9.
PRIMARY CONTAINMENT INTEGRITY	PRIMARY CONTAINMENT INTEGRITY means that the drywell and pressure suppression chamber are intact and all of the following conditions are satisfied: 1. All manual containment isolation valves on lines connected to the reactor coolant system or containment which are not required to be open during accident conditions are closed. 2. At least one door in each airlock is closed and sealed 3. All blind flanges and manways are closed. 4. All automatic primary containment isolation valves and all instrument line check valves are operable or at least one containment isolation valve in each line having an inoperable valve shall be deactivated in the isolated condition. 5. All containment isolation check valves are operable or at least one containment valve in each line having an inoperable valve is secured in the isolated position.
PROTECTIVE ACTION	An action initiated by the protection system when a limit is reached. A PROTECTIVE ACTION can be at a channel or system level.

PROTECTIVE FUNCTION	A system PROTECTIVE ACTION which results from the PROTECTIVE ACTION of the channels monitoring a particular plant condition.
REACTOR POWER OPERATION	REACTOR POWER OPERATION is any operation with the mode switch in the "Startup" or "Run" position with the reactor critical and above 1% design power.
REACTOR VESSEL PRESSURE	Unless otherwise indicated, REACTOR VESSEL PRESSURES listed in the Technical Specifications are those measured by the reactor vessel steam space detectors.
REFUELING INTERVAL	REFUELING INTERVAL applies only to In-service Code Testing Program surveillance tests. For the purpose of designating frequency of these code tests, a REFUELING INTERVAL shall mean at least once every 24 months.
REFUELING OUTAGE	REFUELING OUTAGE is the period of time between the shutdown of the unit prior to a refueling and the startup of the plant after that refueling. For the purpose of designating frequency of testing and surveillance, a REFUELING OUTAGE shall mean a regularly scheduled outage; however, where such outages occur within 11 months of completion of the previous REFUELING OUTAGE, the required surveillance testing need not be performed until the next regularly scheduled outage.
SAFETY LIMIT	The SAFETY LIMITS are limits below which the reasonable maintenance of the cladding and primary systems are assured. Exceeding such a limit is cause for unit shutdown and review by the Nuclear Regulatory Commission before resumption of unit operation. Operation beyond such a limit may not in itself result in serious consequences, but it indicates an operational deficiency subject to regulatory review.
SECONDARY CONTAINMENT INTEGRITY	SECONDARY CONTAINMENT INTEGRITY means that the reactor building is intact and the following conditions are met: 1. At least one door in each access opening is closed. 2. The standby gas treatment system is operable. 3. All automatic ventilation system isolation valves are operable or secured in the isolated position.
SIMULATED AUTOMATIC ACTUATION	SIMULATED AUTOMATIC ACTUATION means applying a simulated signal to the sensor to actuate the circuit in question.
SOURCE CHECK	A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of: (a) a test schedule for <u>n</u> systems, subsystems, trains, or other designated components obtained by dividing the specified test interval into <u>n</u> equal subintervals; (b) the testing of one system, subsystem, train or other designated components at the beginning of each subinterval.

SURVEILLANCE FREQUENCY

Each Surveillance Requirement shall be performed within the specified SURVEILLANCE INTERVAL with a maximum allowable extension not to exceed 25 percent of the specified SURVEILLANCE INTERVAL.

The SURVEILLANCE FREQUENCY establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance schedule and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed during refueling outages.

This limitation of this definition is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

SURVEILLANCE INTERVAL

The SURVEILLANCE INTERVAL is the calendar time between surveillance tests, checks, calibrations, and examinations to be performed upon an instrument or component when it is required to be operable. These tests may be waived when the instrument, component, or system is not required to be operable, but the instrument, component, or system shall be tested prior to being declared operable. The operating cycle interval is 24 months and the 25% tolerance of the definition of "SURVEILLANCE FREQUENCY" is applicable. The refueling interval is 24 months and the 25% tolerance specified in the definition of "SURVEILLANCE FREQUENCY" is applicable.

TOTAL PEAKING FACTOR

The ratio of the fuel rod surface heat flux to the heat flux of an average rod in an identical geometry fuel assembly operating at the core average bundle power.

TRANSITION BOILING

TRANSITION BOILING means the boiling regime between nucleate and film boiling. TRANSITION BOILING is the regime in which both nucleate and film boiling occur intermittently with neither type being completely stable.

TRIP SYSTEM

A TRIP SYSTEM means an arrangement of instrument channel trip signals and auxiliary equipment required to initiate action to accomplish a protective trip function. A TRIP SYSTEM may require one or more instrument channel trip signals related to one or more plant parameters in order to initiate trip system action. Initiation of protective action may require the tripping of a single trip system or the coincident tripping of two trip systems.

2.0 SAFETY LIMITS

2.1 Safety Limits

2.1.1 With the reactor steam dome pressure < 685 psig or core flow < 10% of rated core flow:

THERMAL POWER shall be ≤ 25% of RATED THERMAL POWER.

2.1.2 With the reactor steam dome pressure ≥ 685 psig and core flow ≥ 10% of rated core flow:

MINIMUM CRITICAL POWER RATIO shall be ≥ 1.10 for two recirculation loop operation or ≥ 1.12 for single recirculation loop operation.

2.1.3 Whenever the reactor is in the cold shutdown condition with irradiated fuel in the reactor vessel, the water level shall not be less than 12 inches above the top of the normal active fuel zone.

2.1.4 Reactor steam dome pressure shall be ≤ 1340 psig at any time when irradiated fuel is present in the reactor vessel.

2.2 Safety Limit Violation

With any Safety Limit not met within two hours the following actions shall be met:

2.2.1 Restore compliance with all Safety Limits, and

2.2.2 Insert all insertable control rods.

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

3.0.1 Not Used

3.0.2 Not Used

3.0.3 Not Used

3.0.4 Not Used

3.0.5 Not Used

3.0.6 Not Used

3.0.7 Special Operations LCOs in Section 3.14 allow specified Technical Specifications requirements to be changed to permit performance of special tests and operations. Unless otherwise specified, all other Technical Specification requirements remain unchanged. Compliance with Special Operations LCOs is optional. When a Special Operations LCO is desired to be met but is not met, the ACTIONS of the Special Operations LCO shall be met. When a Special Operations LCO is not desired to be met, entry into a Mode or other specified condition in the Applicability shall only be made in accordance with the other applicable Specifications.

3.0.8 When one or more required snubbers are unable to perform their associated support function(s), any affected supported LCO(s) are not required to be declared not met solely for this reason if risk is assessed and managed, and:

a. the snubbers not able to perform their associated support function(s) are associated with only one train or subsystem of a multiple train or subsystem supported system or are associated with a single train or subsystem supported system and are able to perform their associated support function within 72 hours; or

b. the snubbers not able to perform their associated support function(s) are associated with more than one train or subsystem of a multiple train or subsystem supported system and are able to perform their associated support function within 12 hours.

At the end of the specified period the required snubbers must be able to perform their associated support function(s), or the affected supported system LCO(s) shall be declared not met.

4.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

4.0.1 Not Used

4.0.2 Not Used

4.0.3 If it is discovered that a Surveillance was not performed within its specified Surveillance Frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Surveillance Frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed.

If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

LIMITING CONDITIONS FOR OPERATION

3.1 REACTOR PROTECTION SYSTEM

Applicability:

Applies to the instrumentation and associated devices which initiate a reactor scram.

Objective:

To assure the operability of the reactor protection system.

Specification:

The setpoints, minimum number of trip systems, and minimum number of instrument channels that must be operable for each position of the reactor mode switch shall be as given in Table 3.1.1. The system response times from the opening of the sensor contact up to and including the opening of the trip actuator contacts shall not exceed 50 milli-seconds.

SURVEILLANCE REQUIREMENTS

4.1 REACTOR PROTECTION SYSTEM

Applicability:

Applies to the surveillance of the instrumentation and associated devices which initiate reactor scram.

Objective:

To specify the type and frequency of surveillance to be applied to the protection instrumentation.

Specification:

Instrumentation systems shall be functionally tested and calibrated as indicated in Tables 4.1.1 and 4.1.2 respectively.

PNPS Table 3.1.1 REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENTATION REQUIREMENT

Operable Inst. Channels per Trip System [1]		Trip Function	Trip Level Setting	Modes in Which Function Must Be Operable			Action[1]
Minimum	Avail.			Refuel	Startup/Hot Standby	Run	
1	1	Mode Switch in Shutdown		X[7]	X		A
1	1	Manual Scram		X[7]	X	X	A
		IRM					
3	4	High Flux	≤ 120/125 of full scale	X[7]	X	[5]	A
3	4	Inoperative		X[7]	X	[5]	A
		APRM					
2	3	High Flux	[15]	[17]	[17]	X	A or B
2	3	Inoperative	[13]	X[7]	X[9]	X	A or B
2	3	High Flux (15%)	≤ 15% of Design Power	X[7]	X	[16]	A or B
2	2	High Reactor Pressure	≤ 1063.5 psig	X[10]	X	X	A
2	2	High Drywell Pressure	≤ 2.22 psig	X[8]	X[8]	X	A
2	2	Reactor Low Water Level	≥ 11.6 in. Indicated Level	X[10]	X	X	A
		SDIV High Water Level:	≤ 38 Gallons	X[2][7]	X	X	A
2	2	East					
2	2	West					
4	4	Main Steam Line Isolation Valve Closure	≤ 10% Valve Closure	X[3][6]	X[3][6]	X[6]	A or C
2	2	Turbine Control Valve Fast Closure	≥ 150 psig Control Oil Pressure at Acceleration Relay	X[4]	X[4]	X[4]	A or D
4	4	Turbine Stop Valve Closure	≤ 10% Valve Closure	X[4]	X[4]	X[4]	A or D

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NOTES FOR TABLE 3.1.1

1. There shall be two operable or tripped trip systems for each trip function (e.g., high drywell pressure, reactor low water level, etc.). An instrument channel, satisfying minimum operability requirements for a trip system, may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

   An inoperable channel and/or trip system need not be placed in the tripped condition if this would cause a full scram to occur. When a trip system can be placed in the tripped condition without causing a full scram to occur, place the trip system with the most inoperable channels in the tripped condition, per the table below. If both systems have the same number of inoperable channels, place either trip system in the tripped condition, per the table below.

Condition	Required Action	Completion Time
a. With less than the mininum required operable channels per trip function in one trip system.	Place associated trip system in trip or*	12 hours
b. With less than the minimum required operable channels per trip function, in both trip systems.	Place one trip system in trip or*	6 hours
c. If full scram trip capability is not available for a given trip function	Restore RPS trip capability or*	1 hour

* Initiate the actions required by Table 3.1.1 and specified in Actions A through D below for that function:

A. Initiate insertion of operable rods and complete insertion of all operable rods within four (4) hours.

B. Reduce power level to IRM range and place mode switch in the startup/hot standby position within eight (8) hours.

C. Reduce turbine load and close main steam line isolation valves within eight (8) hours.

D. Reduce power to less than 32.5% of design.

NOTES FOR TABLE 3.1.1 (Cont)

2. Permissible to bypass, with control rod block, for reactor protection system reset in refuel and shutdown positions of the reactor mode switch.
3. Permissible to bypass when reactor pressure is < 576 psig.
4. Permissible to bypass when turbine first stage pressure is less than ≤ 112 psig.
5. IRM's are bypassed when APRM's are onscale and the reactor mode switch is in the run position.
6. The design permits closure of any two lines without a scram being initiated.
7. When the reactor mode switch is in the Refuel position, the reactor vessel head is removed, and control rods are inserted in all core cells containing one or more fuel assemblies, these scram functions are not required.
8. Not required to be operable when primary containment integrity is not required.
9. Not required while performing low power physics tests at atmospheric pressure during or after refueling at power levels not to exceed 5 MW(t).
10. Not required to be operable when the reactor pressure vessel head is not bolted to the vessel.
11. Deleted
12. Deleted
13. An APRM will be considered inoperable if there are less than 2 LPRM inputs per level or there is less than 50% of the normal complement of LPRM's to an APRM.
14. Deleted
15. The APRM high flux trip level setting for the flow bias function shall be as specified in the CORE OPERATING LIMITS REPORT. The APRM high flux trip level setting shall in no case exceed 120% of rated thermal power.
16. The APRM (15%) high flux scram is bypassed when in the run mode.
17. The APRM flow biased high flux scram is bypassed when in the refuel or startup/hot standby modes.
18. Deleted.

PNPS TABLE 4.1.1

REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENTATION FUNCTIONAL TESTS

MINIMUM FUNCTIONAL TEST FREQUENCIES FOR SAFETY INSTRUMENTATION AND CONTROL CIRCUITS

	Functional Test	Minimum Frequency (3)
Mode Switch in Shutdown	Place Mode Switch in Shutdown	Each Refueling Outage
Manual Scram	Trip Channel and Alarm	Every 3 Months
RPS Channel Test Switch (5)	Trip Channel and Alarm	Once per week
IRM		
High Flux	Trip Channel and Alarm (4)	Once Per Week During Refueling and Before Each Startup
Inoperative	Trip Channel and Alarm	Once Per Week During Refueling and Before Each Startup
APRM		
High Flux	Trip Output Relays (4)	Every 3 Months
Inoperative	Trip Output Relays (4)	Every 3 Months
Flow Bias	Trip Output Relays (4)	Every 3 Months
High Flux (15%)	Trip Output Relays (4)	Once Per Week During Refueling and Before Each Startup
High Reactor Pressure	Trip Channel and Alarm (4)	Every 3 Months
High Drywell Pressure	Trip Channel and Alarm (4)	Every 3 Months
Reactor Low Water Level	Trip Channel and Alarm (4)	Every 3 Months
High Water Level in Scram Discharge Tanks	Trip Channel and Alarm (4)	Every 3 Months
Main Steam Line Isolation Valve Closure	Trip Channel and Alarm	Every 3 Months
Turbine Control Valve Fast Closure	Trip Channel and Alarm	Every 3 Months
Turbine First Stage Pressure Permissive	Trip Channel and Alarm (4)	Every 3 Months
Turbine Stop Valve Closure	Trip Channel and Alarm	Every 3 Months
Reactor Pressure Permissive	Trip Channel and Alarm (4)	Every 3 Months

NOTES FOR TABLE 4.1.1

1. Deleted

2. Deleted

3. Functional tests are not required when the systems are not required to be operable or are tripped.

   If tests are missed, they shall be performed prior to returning the systems to an operable status.

4. This instrumentation is exempted from the instrument channel test definition. This instrument channel functional test will consist of injecting a simulated electrical signal into the measurement channels.

5. Test RPS channel after maintenance.

PNPS TABLE 4.1.2
REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENT CALIBRATION
MINIMUM CALIBRATION FREQUENCIES FOR REACTOR PROTECTION INSTRUMENT CHANNELS

Instrument Channel	Calibration Test (5)	Minimum Frequency (2)
IRM High Flux	Comparison to APRM on Controlled Shutdowns	Note (4)
	Full Calibration	Once per Operating Cycle
APRM High Flux		
Output Signal	Heat Balance (8)	Once every 3 Days
Flow Bias Signal	Calibrate Flow Comparator and Flow Bias Network	At least once every 18 Months
	Calibrate Flow Bias Signal (1)	Every 3 Months
LPRM Signal	TIP System Traverse	Every 1000 Effective Full Power Hours
High Reactor Pressure	Note (7)	Note (7)
High Drywell Pressure	Note (7)	Note (7)
Reactor Low Water Level	Note (7)	Note (7)
High Water Level in Scram Discharge Tanks	Note (7)	Note (7)
Main Steam Line Isolation Valve Closure	Note (6)	Note (6)
Turbine First Stage Pressure Permissive	Note (7)	Note (7)
Turbine Control Valve Fast Closure	Standard Pressure Source	Every 3 Months
Turbine Stop Valve Closure	Note (6)	Note (6)
Reactor Pressure Permissive	Note (7)	Note (7)

NOTES FOR TABLE 4.1.2

1. Adjust the flow bias trip reference, as necessary, to conform to a calibrated flow signal.

2. Calibration tests are not required when the systems are not required to be operable or are tripped.

3. Deleted.

4. Maximum frequency required is once per week.

5. Response time is not a part of the routine instrument channel test, but will be checked once per operating cycle.

6. Physical inspection and actuation of these position switches will be performed during the refueling outages.

7. Calibration of these devices will be performed during refueling outages.

   To verify transmitter output, a daily instrument check will be performed. Calibration of the associated analog trip units will be performed concurrent with functional testing as specified in Table 4.1.1.

8. Not required to be performed until 12 hours after thermal power is $\geq$ 25% rated thermal power.

LIMITING CONDITION FOR OPERATION

3.2 PROTECTIVE INSTRUMENTATION

Applicability:

Applies to the plant instrumentation which initiates and controls a protective function.

Objective:

To assure the operability of protective instrumentation.

Specifications:

A. Primary Containment Isolation Functions

When primary containment integrity is required, the limiting conditions of operation for the instrumentation that initiates primary containment isolation are given in Table 3.2.A.

B. Core and Containment Cooling Systems - Initiation & Control

The limiting conditions for operation for the instrumentation that initiates or controls the core and containment cooling systems are given in Table 3.2.B. This instrumentation must be operable when the system(s) it initiates or controls are required to be operable as specified in Section 3.5.

SURVEILLANCE REQUIREMENT

4.2 PROTECTIVE INSTRUMENTATION

Applicability:

Applies to the surveillance requirement of the instrumentation that initiates and controls protective function.

Objective:

To specify the type and frequency of surveillance to be applied to protective instrumentation.

Specifications:

A. Primary Containment Isolation Functions

Instrumentation shall be functionally tested and calibrated as indicated in Table 4.2.A.

System logic shall be functionally tested as indicated in Table 4.2.A.

B. Core and Containment Cooling Systems - Initiation & Control

Instrumentation shall be functionally tested, calibrated and checked as indicated in Table 4.2.B.

System logic shall be functionally tested as indicated in Table 4.2.B.

LIMITING CONDITION FOR OPERATION

3.2 PROTECTIVE INSTRUMENTATION (Cont)

C. Control Rod Block Actuation

1. The limiting conditions of operation for the instrumentation that initiates control rod block are given in Table 3.2.C-1. The trip setpoints for this instrumentation shall be set consistent with Table 3.2.C-2.

D. Radiation Monitoring Systems - Isolation & Initiation Functions

1. Reactor Building Isolation and Control System and Standby Gas Treatment System

   The limiting conditions for operation are given in Table 3.2.D.

SURVEILLANCE REQUIREMENT

4.2 PROTECTIVE INSTRUMENTATION (Cont)

C. Control Rod Block Actuation

1. Instrumentation shall be functionally tested, calibrated and checked as indicated in Table 4.2.C.

   System logic shall be functionally tested as indicated in Table 4.2.C.

D. Radiation Monitoring Systems - Isolation & Initiation Functions

1. Reactor Building Isolation and Control System and Standby Gas Treatment System

   Instrumentation shall be functionally tested, calibrated and checked as indicated in Table 4.2.D.

   System logic shall be functionally tested as indicated in Table 4.2.D.

LIMITING CONDITION FOR OPERATION

3.2 PROTECTIVE INSTRUMENTATION (Cont)

E. Drywell Leak Detection

The limiting conditions of operation for the instrumentation that monitors drywell leak detection are given in Section 3.6.C.

F. Surveillance Information Readouts

The limiting conditions for the instrumentation that provides surveillance information readouts are given in Table 3.2.F.

SURVEILLANCE REQUIREMENT

4.2 PROTECTIVE INSTRUMENTATION (Cont)

E. Drywell Leak Detection

Instrumentation shall be functionally tested, calibrated and checked as indicated in Section 4.6.C.

F. Surveillance Information Readouts

Instrumentation shall be calibrated and checked as indicated in Table 4.2.F.

LIMITING CONDITION FOR OPERATION

3.2 PROTECTIVE INSTRUMENTATION (Cont)

G. Recirculation Pump Trip/Alternate Rod Insertion Initiation.

This system is only required when the reactor mode switch is in the RUN mode.

The recirculation pump trip system causes a pump trip and the alternate rod insertion system provides for initiating control rod insertion on a signal of high reactor pressure or low-low reactor water level when the mode select switch is in the RUN mode.

The limiting conditions for operation for the instrumentation are listed in Table 3.2-G.

SURVEILLANCE REQUIREMENTS

4.2 PROTECTIVE INSTRUMENTATION (Cont)

G. Recirculation Pump Trip/Alternate Rod Insertion

Surveillance for instrumentation which initiates Recirculation Pump Trip and Alternate Rod Insertion shall be specified in Table 4.2-G.

LIMITING CONDITIONS FOR OPERATION

3.2 PROTECTIVE INSTRUMENTATION (Cont)

H. Drywell Temperature

1. The drywell temperature shall be maintained within the following limits when the reactor coolant temperature is above 212°F.

   Above elevation 40': ≤ 194°F

   Equal to or Below elevation 40': ≤ 150°F

   Upon determination that the drywell temperature at any elevation has exceeded the above limits, the drywell temperature at each elevation shall be logged every 30 minutes. The drywell temperature shall be reduced to within the limits within 24 hours; otherwise, corrective action shall be as specified in 3.2.H.2, 3.2.H.3.

2. If the drywell temperature has exceeded either limit of 3.2.H.1 for greater than 24 hours, an engineering evaluation shall immediately be initiated to assess potential damage and render a determination of ability of safety related equipment to perform its intended function.

   If either limit of section 3.2.H.1 has been exceeded for greater than 24 hours, further action to justify continued operation shall be determined by an engineering evaluation, which must be completed within one week.

3. If the requirements of 3.2.H.2 have not been met an orderly Shutdown shall be initiated and the reactor shall be in a Cold Shutdown condition within 24 hours.

SURVEILLANCE REQUIREMENTS

4.2 PROTECTIVE INSTRUMENTATION (Cont)

H. Drywell Temperature

1. When reactor coolant temperature is above 212°F, the drywell air temperature limits will be determined by reading the instruments listed in Table 3.2.H. These instruments shall be logged once per shift, and each reading compared to the limits of Section 3.2.H.1.

2. Instrumentation shall be calibrated and checked as indicated in Table 4.2.H.

LIMITING CONDITIONS FOR OPERATION

3.2 PROTECTIVE INSTRUMENTATION (Cont)

4. If the drywell temperature at any elevation exceeds 215°F and the temperature cannot be reduced to below 215°F within 30 minutes a reactor shutdown shall be initiated and the reactor shall be in cold shutdown condition within 24 hours.

5. The limiting conditions of operation for the instrumentation that monitors drywell temperature are given in Table 3.2.H.

SURVEILLANCE REQUIREMENTS

4.2 PROTECTIVE INSTRUMENTATION (Cont)

TABLE 3.2.A

INSTRUMENTATION THAT INITIATES PRIMARY CONTAINMENT ISOLATION

Minimum # of Operable Instrument Channels Per Trip System (1)	Instrument	Trip Level Setting	Action (2)
2(7)	Reactor Low Water Level	≥ 11.6" indicated level (3)	A and D
1	Reactor High Pressure	≤ 76 psig	D
2	Reactor Low-Low Water Level	at or above - 46.4 in. indicated level (4)	A
2	Reactor High Water Level	≤55.4" indicated level (5)	B
2(7)	High Drywell Pressure	≤ 2.22 psig	A
2	Low Pressure Main Steam Line	≥ 810 psig (8)	B
2(6)	High Flow Main Steam Line	≤ 136% of rated steam flow	B
2	Main Steam Line Tunnel Exhaust Duct High Temperature	≤ 175° F	B
2	Turbine Basement Exhaust Duct High Temperature	≤ 155° F	B
1	Reactor Water Cleanup System (RWCU) High Flow	≤ 300% of rated flow	C
1	RWCU Back Wash Receiver Tank Room High Temperature	≤ 148° F	C
1	RWCU Heat Exchanger and Pump Rooms High Temperature	≤ 148° F	C
1	RWCU Line in RHR Valve Room "A" High Temperature	≤ 148° F	C
1	RWCU Line Near East CRD Modules High Temperature	≤ 148° F	C

NOTES FOR TABLE 3.2.A

1. Whenever Primary Containment integrity is required by Section 3.7, there shall be two operable or tripped trip systems for each function. An instrument channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter; or, where only one channel exists per trip system, the other trip system shall be operable.

2. Action

   If the minimum number of operable instrument channels cannot be met for one of the trip systems of a trip function, the appropriate conditions listed below shall be followed:

   If placing the inoperable channel(s) in the tripped condition would not cause an isolation, the inoperable channel(s) and/or that trip system shall be placed in the tripped condition within one hour (twelve hours for Reactor Low Water Level and High Drywell Pressure) or initiate the action required by Table 3.2.A for the affected trip functions.

   If placing the inoperable channel(s) in the tripped condition would cause an isolation, the inoperable channel(s) shall be restored to operable status within two hours (six hours for Reactor Low Water Level and High Drywell Pressure) or initiate the Action required by Table 3.2.A for the affected trip function.

   If the minimum number of operable instrument channels cannot be met for both trip systems, place at least one trip system (with the most inoperable channels) in the tripped condition within one hour or initiate the appropriate Action required by Table 3.2.A listed below for the affected trip function.

   A. Initiate an orderly shutdown and have the reactor in Cold Shutdown Condition in 24 hours.

   B. Initiate an orderly load reduction and have Main Steam Lines isolated within eight hours.

   C. Isolate Reactor Water Cleanup System.

   D. Isolate Shutdown Cooling.

NOTES FOR TABLE 3.2.A (Cont)

3. Instrument set point corresponds to 137.86 inches above top of active fuel.

4. Instrument set point corresponds to 79.86 inches above top of active fuel.

5. Not required in Run Mode (bypassed by Mode Switch).

6. Each steam line is monitored by two instrument trip channels per trip system. Therefore, the minimum number of main steam line high flow instruments required to be operable is four per main steam line unless the line is isolated.

7. These signals also start SBGTS and initiate secondary containment isolation.

8. Only required in Run Mode (interlocked with Mode Switch).

9. Deleted.

PNPS
TABLE 3.2.B

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
2	Reactor Low-Low Water Level	at or above -46.3 in. indicated level (4)	1. In conjunction with Low Reactor Pressure, initiates Core Spray and LPCI. 2. In conjunction with High Drywell Pressure, 94.4-115.6 second time delay and LPCI or Core Spray pump interlock initiates Auto Blowdown (ADS). 3. Initiates HPCI; RCIC. 4. Initiates starting of Diesel Generators.
2	Reactor High Water Level	$\leq$+45.3" indicated level	Trips HPCI and RCIC turbines.
1	Reactor Low Level (inside shroud)	>-151" indicated level	Prevents inadvertent operation of containment spray during accident condition. (Indication of 2/3 core coverage.)
2	Containment High Pressure	$1.55 \leq p \leq 1.82$ psig	Prevents inadvertent operation of containment spray during accident condition. Instrument is set to trip at or before 1.82 increasing and reset at or before 1.55 decreasing.

TABLE 3.2.B (Cont)

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
2 (7)	High Drywell Pressure	≤2.22 psig	1. Initiates Core Spray; LPCI; HPCI. 2. In conjunction with Low-Low Reactor Water Level, 94.4-115.6 second time delay and LPCI or Core Spray pump running, initiates Auto Blowdown (ADS) 3. Initiates starting of Diesel Generators 4. In conjunction with Reactor Low Pressure initiates closure of HPCI vacuum breaker containment isolation valves.
1	Reactor Low Pressure	400 psig ± 5	Permissive for opening Core Spray and LPCI Admission valves.
1	Reactor Low Pressure	≤76 psig	In conjunction with PCIS signal permits closure of RHR (LPCI) injection valves.
1	Reactor Low Pressure	400 psig ± 5	In conjunction with Low-Low Reactor Water Level initiates Core Spray and LPCI.
2	Reactor Low Pressure	900 psig ± 5	Prevents actuation of LPCI break detection circuit.
2	Reactor Low Pressure	80 psig ± 5	Isolates HPCI and in conjunction with High Drywell Pressure initiates closure of HPCI vacuum breaker containment isolation valves.

TABLE 3.2.B (Cont)

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
1	Core Spray Pump Start Timer	0.21<t<1 sec	Initiates sequential starting of CSCS pumps on any auto start.
1	LPCI Pump Start Timer	4.16<t<5.84 sec.	
1	LPCI Pump Start Timer	9.5<t<11.5 sec.	
1	Auto Blowdown Timer	≥94.4,≤115.6 sec.	In conjunction with Low Low Reactor Water Level, High Drywell Pressure and LPCI or Core Spray Pump running interlock, initiates Auto Blowdown.
2	ADS Drywell Pressure Bypass Timer	9≤t≤15.4 min.	Permits starting CS and LPCI pumps and actuating ADS SRV's if RPV water level is low and drywell pressure is not high.
2	RHR (LPCI) Pump Discharge Pressure Interlock	150± 10 psig	Defers ADS actuation pending confimation of Low Pressure Core Cooling System operation. (LPCI or Core Spray Pump running interlock.)
2	Core Spray Pump Discharge Pressure Interlock	150± 10 psig	
2	Emergency Bus Voltage Relay	20-25% of rated voltage resets at less than or equal to 50%	1. Permits closure of the Diesel Generator to an unloaded emergency bus. 2. Permits starting of CSCS 4 kV motors.

TABLE 3.2.B (Cont)

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
2	Startup Transformer Loss of Voltage	At 0 Volts between $0.96 \leq t \leq 1.34$ seconds Time Delay	1. Trips Startup Transformer to Emergency Bus Breaker. 2. Locks out automatic closure of Startup Transformer to Emergency Bus. 3. Initiates starting of Diesel Generators in conjunction with loss of auxiliary transformer. 4. Prevents simultaneous starting of CSCS components. 5. Starts load shedding logic for Diesel Operation in conjunction with (a) Low Low Reactor Water Level and Low Reactor Pressure or (b) High Drywell Pressure or (c) Core Standby Cooling System components in service in conjunction with Auxiliary Transformer breaker open.

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
2	Startup Transformer Degraded Voltage	3878.7V ± .51% with 10.24 ± 0.36 seconds time delay.	1. Trips Startup Transformer to Emergency Bus Breaker. 2. Locks out automatic closure of Startup Transformer to Emergency Bus. 3. Initiates starting of Diesel Generators in conjunction with loss of Auxiliary Transformer. 4. Prevents simultaneous starting of CSCS components. 5. Starts load shedding logic for Diesel Operation in conjunction with a) Low Low Reactor Water Level and Low Reactor Pressure or b) High Drywell Pressure or c) Core Standby Cooling System components in service in conjunction with Auxiliary Transformer breaker open.

PNPS
TABLE 3.2.B (Cont)

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
1	RHR (LPCI) Trip System bus power monitor	NA	Monitors availability of power to logic systems.
1	Core Spray Trip System bus power monitor	NA	Monitors availability of power to logic systems.
1	ADS Trip System bus power monitor	NA	Monitors availability of power to logic systems and valves.
1	HPCI Trip System bus power monitor	NA	Monitors availability of power to logic systems.
1	RCIC Trip System bus power monitor	NA	Monitors availability of power to logic systems.
2	Recirculation Pump A d/p	≤2 psid	Operates RHR (LPCI) break detection logic which directs cooling water into unbroken recirculation loop.
2	Recirculation Pump B d/p	≤2 psid	
2	Recirculation Jet Pump Riser d/p A>B	0.5<p<1.5 psid	
1	Core Spray Sparger to Reactor Pressure Vessel d/p	-1(±1.5) psid	Alarm to detect Core Spray sparger pipe break.

TABLE 3.2.B (CONT)

INSTRUCTIONS THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
2	Condensate Storage Tank Low Level	≥ 46" above tank zero (a)	Provides interlock to HPCI pump suction valves.
2	Suppression Chamber High Level	≤ 1'11" below torus zero	
1	RCIC Turbine Steam Line High Flow	≤ 300% of rated steam flow	(2)
2	RCIC Turbine Compartment Wall	≤ 168°F	(2)
2	RCIC Exhaust Duct Torus Cavity	≤ 148°F	(2)
2	RCIC Valve Station Area Wall	≤ 198°F	(2)
4	RCIC Steam Line Low Pressure	77 > P > 63 psig	(2)(5)(6)
1	HPCI Turbine Steam Line High Flow	≤ 296% of rated flow	(3)
2	HPCI Turbine Compartment Exhaust Duct	≤ 168°F	(3)
2	HPCI Exhaust Duct Torus Cavity	≤ 198°F	(3)
2	HPCI/RHR Valve Station Area Exhaust Duct	≤ 168°F	(3)

(a) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service. The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise the channel shall be declared inoperable. Setpoints more conservative than NTSP are acceptable provided that the as-found and as-left tolerances apply to the actual setpoint implemented in the Surveillance procedure to confirm channel performance. The NTSP and the methodologies used to determine the as-found and as-left tolerances are specified in the Pilgrim Setpoint calculation for Condensate Tank Low Level Instrumentation, IN1-245.

NOTES FOR TABLE 3.2.B

1. Whenever any CSCS subsystem is required by Section 3.5 to be operable, there shall be two (Note 5) operable trip systems. If the first column cannot be met for one of the trip systems, that system shall be repaired or the reactor shall be placed in the Cold Shutdown Condition within 24 hours after this trip system is made or found to be inoperable.

2. Close isolation valves in RCIC subsystem.

3. Close isolation valves in HPCI subsystem.

4. Instrument set point corresponds to 79.96 inches above top of active fuel.

5. RCIC has only one trip system for these sensors.

6. Does not include static head of 17.5 psi.

7. Only required to be Operable in Run, Startup, and Hot Shutdown Modes.

PNPS
TABLE 3.2.B.1

INSTRUMENTATION THAT MONITORS EMERGENCY BUS VOLTAGE

Minimum # of Operable Instrument Channels Per Trip system	Function	Setting	Remarks
1	Emergency 4160V Buses A5 & A6 Degraded Voltage Annunciation (1)	3958.5V + 0.5%-0.24% with 10.24 ± 0.36 seconds time delay	Alerts Operator to possible degraded voltage conditions. Provides permissive to initiate load shedding in conjunction with LOCA signal.

(1) In the event that the alarm system is determined inoperable, commence logging safety related bus voltage every ½ hour until such time as the alarm is restored to operable status.

PNPS
TABLE 3.2.C.1

INSTRUMENTATION THAT INITIATES ROD BLOCKS

Trip Function	Operable Channels per Trip Function: Minimum	Operable Channels per Trip Function: Available	Required Operational Conditions	Notes
Rod Block Monitor(Power Dependent)	2	2	Run, with limiting control rod pattern, and reactor power > LPSP	(2)(5)
Rod Block Monitor Inoperative	2	2	Run, with limiting control rod pattern, and reactor power > LPSP	(2)(5)
Rod Block Monitor Downscale	2	2	Run, with limiting control rod pattern, and reactor power > LPSP	(2)(5)
Reactor Mode Switch in Shutdown	2	2	Shutdown	(7)

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NOTES FOR TABLE 3.2.C-1

1. Deleted

2. a. With one RBM Channel inoperable:

   (1) restore the inoperable RBM channel to operable status within 24 hours; otherwise place one rod block monitor channel in the tripped condition within the next hour, and;

   (2) prior to control rod withdrawal, perform an instrument function test of the operable RBM channel.

   b. With both RBM channels inoperable, place at least one inoperable rod block monitor channel in the tripped condition within one hour.

3. Deleted

4. Deleted

5. RBM operability is required in the run mode in the presence of a limiting rod pattern with reactor power greater than the RBM low power setpoint (LPSP). A limiting rod pattern exists when:

   MCPR < 1.41 for reactor power $\geq 90\%$

   MCPR < 1.72 for reactor power $< 90\%$

   The allowable value for the LPSP is $\leq 25.9\%$ of rated core thermal power.

6. Deleted

7. With one or more Reactor Mode Switch - Shutdown Position channels inoperable, suspend control rod withdrawal and initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies immediately.

PNPS
TABLE 3.2.C-2
CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

Trip Function	Trip Setpoint
Rod Block Monitor (Power Dependent)	(1) (3)
Rod Block Monitor Inoperative	Not Applicable
Rod Block Monitor Downscale	(1) (3)
Mode Switch in Shutdown	Not Applicable

(1) The trip level setting shall be as specified in the CORE OPERATING LIMITS REPORT.

(2) Deleted

(3) The RBM bypass time delay (t_{d2}) shall be < 2.0 seconds.

TABLE 3.2.D

RADIATION MONITORING SYSTEMS THAT INITIATE AND/OR ISOLATE

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Action (2)
2	Refuel Area Exhaust Monitors	Upscale, <100 mr/hr	A or B
2	Refuel Area Exhaust Monitors	Downscale	A or B

NOTES FOR TABLE 3.2.D

1. Whenever the systems are required to be operable, there shall be two operable or tripped trip systems. If this cannot be met, the indicated action shall be taken.

2. Action

   A. Cease movement of recently irradiated fuel assemblies and operations with potential to drain the reactor vessel (OPDRVs).

   B. Isolate secondary containment and start the standby gas treatment system during movement of recently irradiated fuel assemblies and operations with potential to drain the reactor vessel (OPDRVs).

PNPS

TABLE 3.2.F

<u>SURVEILLANCE INSTRUMENTATION</u>

Minimum # of Operable Instrument Channels	Instrument #	Parameter	Type Indication and Range	Notes
2	640-29A & B	Reactor Water Level	Indicator 0-60"	(1) (2) (3)
2	640-25A & B	Reactor Pressure	Indicator 0-1200 psig	(1) (2) (3)
2	TRU-9044 TRU-9045	Drywell Pressure	Recorder 0-80 psia	(1) (2) (3)
2	TRU-9044 TI-9019	Drywell Temperature	Recorder, Indicator 0-400°F	(1) (2) (3)
2	TRU-9045 TI-9018	Suppression Chamber Air Temperature	Recorder, Indicator 0-400°F	(1) (2) (3)
2	LR-5038 LR-5049	Suppression Chamber Water Level	Recorder -7 to +7 inches	(1) (2) (3)
1	NA	Neutron Monitoring	SRM, IRM, LPRM 0 to 100% power	(1) (2) (3) (4)

TABLE 3.2.F (Cont)

SURVEILLANCE INSTRUMENTATION

Minimum # of Channels	Operable Instrument Instrument #	Parameter	Type Indication and Range	Notes
2	TI-5021-2A TRU-5021-1A TI-5022-2B TRU-5022-1B	Suppression Chamber Water Temperature Suppression Chamber Water Temperature	Indicator/ Multipoint Recorder 30-230°F (Bulk) Indicator/ Multipoint Recorder 30-230°F (Bulk)	(1) (2) (3) (4)) (1) (2) (3) (4)
1	PID-5021	Drywell/Torus Diff. Pressure	Indicator - .25 - +3.0 psig	(1) (2) (3) (4)
1	PID-5067A PID-5067B	Drywell Pressure Torus Pressure	Indicator -.25 - +3.0 psig Indicator -1.0 - +2.0 psig	(1) (2) (3) (4)
1/Valve	(a) Primary or (b) Backup	Safety/Relief Valve Position	a) Acoustic monitor b) Thermocouple	(5)
1/Valve	(a) Primary or (b) Backup	Safety Valve Position Indicator	a) Acoustic monitor b) Thermocouple	(5)
2	LI-1001-604A LR- 1001-604A LI-1001- 604B LR-1001- 604B	Torus Water Level (Wide Range) Torus Water Level (Wide Range)	Indicator /Multipoint Recorder 0 - 300"H_2O Indicator /Multipoint Recorder 0 - 300"H_2O	(1) (2) (3) (4) (1) (2) (3) (4)

TABLE 3.2.F (Cont)

SURVEILLANCE INSTRUMENTATION

Minimum # of Operable Instrument Channels	Instrument #	Parameter	Type Indication and Range	Notes
	(PI 1001-600A (PR 1001-600A	Containment Pressure, (High Range)	Indicator/Multipoint Recorder 0-225 psig	(4) (1) (2) (3)
2	(			
	(PI 1001-600B (PR 1001-600B	Containment Pressure, (High Range)	Indicator/Multipoint Recorder 0-225 psig	(4) (1) (2) (3)
	(PI 1001-601A (PR 1001-600A	Containment Pressure, (Low Range)	Indicator/Multipoint Recorder -5 to 5 psig	(4) (1) (2) (3)
2	(			
	(PI 1001-601B (PR 1001-600B	Containment Pressure, (Low Range)	Indicator/Multipoint Recorder -5 to 5 psig	(4) (1) (2) (3)
2	(RIT 1001-606A (RIT 1001-606B (RR 1001-606A (RR 1001-606B	Containment High Radiation (Drywell)	Monitor/Multipoint Recorder 1 to $1x10^7$ R/hr	(4) (7)
1	RI 1001-609 RR 1001-608	Reactor Building Vent	Indicator/Multipoint Recorder 10^{-1} to 10^4 R/hr	(4) (7)
1	RI 1001-608 RR 1001-608	Main Stack Vent	Indicator/Multipoint Recorder 10^{-1} to 10^4 R/hr	(4) (7)
1	RI 1001-610 RR 1001-608	Turbine Building Vent	Indicator/Multipoint Recorder 10^{-1} to 10^4 R/hr	(4) (7)

NOTES FOR TABLE 3.2.F

(1) With less than the minimum number of instrument channels, restore the inoperable channel(s) within 30 days.

(2) With the instrument channel(s) providing no indication to the control room, restore the indication to the control room within seven days.

(3) If the requirements of notes (1) or (2) cannot be met, an orderly shutdown shall be initiated and the reactor shall be in the Cold Shutdown Condition within 24 hours.

(4) These surveillance instruments are considered to be redundant to each other.

(5) At a minimum, the primary or backup parameter indicators shall be operable for each valve when the valves are required to be operable. With both primary and backup instrument channels inoperable either return one (1) channel to operable status within 31 days or be in a shutdown mode within 24 hours.

The following instruments are associated with the safety/relief and safety valves:

Valve	Primary Acoustic Monitor	Backup Tail Pipe Temperature Thermocouple
203-3A	ZT-203-3A	TE6285
203-3B	ZT-203-3B	TE6286
203-3C	ZT-203-3C	TE6287
203-3D	ZT-203-3D	TE6288
203-4A	ZT-203-4A	TE6274-B
203-4B	ZT-203-4B	TE6275-B

(6) Deleted.

(7) With less than the minimum number of operable instrument channels, restore the inoperable channels to operable status within 7 days or prepare and submit a special report to the Commission within 14 days of the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the channels to operable status.

PNPS
TABLE 3.2-G

INSTRUMENTATION THAT INITIATES RECIRCULATION PUMP TRIP
AND
ALTERNATE ROD INSERTION

Minimum Number of Operable or Tripped Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting
2	High Reactor Dome Pressure	≤1210 psig
2	Low-Low Reactor Water Level	≥-46.3" indicated level

Actions (1) There shall be two (2) operable trip systems for each function.

(a) If the minimum number of operable or tripped instrument channels for one (1) trip system cannot be met, restore the trip system to operable status within 14 days or be in at least hot shutdown within 24 hours.

(b) If the minimum operability conditions (1.a) cannot be met for both (2) trip systems, be in at least hot shutdown within 24 hours.

PNPS
TABLE 3.2.H

DRYWELL TEMPERATURE SURVEILLANCE INSTRUMENTATION

Minimum # of Operable Elements	Instrument #	Nominal Instrument Elevation	Type	Note
Above 40 Feet Elevation				
1/ELEV	TE-5050A 1/2 TE-5050B 1/2	80' 80'	RTD	(1) (2) (4)
1/ELEV	TE-5050C 1/2 TE-5050D 1/2	87' 87'	RTD	(1) (2) (4)
1/ELEV	TE-5050E 1/2 TE-5050F 1/2	60' 60'	RTD	(1) (2) (4)
Below 40 Feet Elevation				
1/ELEV	TE-5050G 1/2 TE-5050H 1/2	41'	RTD	(1) (3) (4)
1/ELEV	TE-5050J 1/2 OR TE-5050K 1/2	32'	RTD	(1) (3) (4)

Notes:

1. The 5050 series temperature elements are dual-elements.

2. At least one element of one RTD on each elevation shall be operable.

3. At least one element of one RTD on elevation 41 and one element of one of the RTD's at nominal elevation 32 shall be operable.

4. If the minimum number of operable RTD's as specified in Note 2 and 3 above are not available and cannot be made available within 24 hours, an orderly shutdown shall be initiated and the reactor shall be in a Cold Shutdown condition within 24 hours of shutdown initiation.

TABLE 4.2.A

MINIMUM TEST AND CALIBRATION FREQUENCY FOR PCIS

	Instrument Channel (5)	Instrument Functional Test		Calibration Frequency	Instrument Check
1)	Reactor High Pressure	(1)		Once/3 months	None
2)	Reactor Low-Low Water Level	Once/3 months	(7)	(7)	Once/day
3)	Reactor High Water Level	Once/3 months	(7)	(7)	Once/day
4)	Main Steam High Temp.	(1)		Once/24 months	None
5)	Main Steam High Flow	Once/3 months	(7)	(7)	Once/day
6)	Main Steam Low Pressure	Once/3 months	(7)	(7)	Once/day
7)	Reactor Water Cleanup System (RWCU) High Flow	(1)		Once/3 months	Once/day
8)	RWCU Back Wash Receiver Tank Room High Temperature	(1)		Once/24 months	None
9)	RWCU Heat Exchanger and Pump Room's High Temperature	(1)		Once/24 months	None
10)	RWCU Line in RHR Valve Room "A" High Temperature	(1)		Once/24 months	None
11)	RWCU Line Near East CRD Modules High Temperature	(1)		Once/24 months	None

	Logic System Functional Test (4)(6)	Frequency
1)	Main Steam Line Isolation Vvs. Main Steam Line Drain Vvs. Reactor Water Sample Vvs.	Once/Operating Cycle
2)	RHR - Isolation Vv. Control Shutdown Cooling Vvs. Head Spray Discharge to Radwaste	Once/Operating Cycle
3)	Reactor Water Cleanup Isolation	Once/Operating Cycle
4)	Drywell Isolation Vvs. TIP Withdrawal Atmospheric Control Vvs. Sump Drain Valves	Once/Operating Cycle
5)	Standby Gas Treatment System Reactor Building Isolation	Once/Operating Cycle

PNPS
TABLE 4.2.B

MINIMUM TEST AND CALIBRATION FREQUENCY FOR CSCS

	Instrument Channel	Instrument Functional Test	Calibration Frequency	Instrument Check
1)	Reactor Water Level	(1) (7)	(7)	Once/day
2)	Drywell Pressure	(1) (7)	(7)	Once/day
3)	Reactor Pressure	(1) (7)	(7)	Once/day
4)	Auto Sequencing Timers	NA	Once/Operating Cycle	None
5)	ADS - LPCI or CS Pump Disch. Pressure Interlock	(1)	Once/3 months	None
6)	Start-up Transf. (4160V)			
	a) Loss of Voltage Relays	Monthly	Once/Operating Cycle	None
	b) Degraded Voltage Relays	Monthly	Once/Operating Cycle	None
7)	Trip System Bus Power Monitors	Once/Operating Cycle	NA	Once/day
8)	Recirculation System d/p	(1)	Once/3 months	Once/day
9)	Core Spray Sparger d/p	NA	Once/18 months	Once/day
10)	Steam Line High Flow (HPCI & RCIC)	(1)	Once/3 months	None
11)	Steam Line High Temp. (HPCI & RCIC)	(1)	Once/24 months	None
12)	Safeguards Area High Temp.	(1)	Once/24 months	None

MINIMUM TEST AND CALIBRATION FREQUENCY FOR CSCS

	Instrument Channel	Instrument Functional Test	Calibration Frequency	Instrument Check
13)	RCIC Steam Line Low Pressure	(1)	Once/12 months	None
14)	HPCI Suction Tank Levels	(1)	Once/3 months	None
15)	Emergency 4160V Buses A5 & A6 Loss of Voltage Relays	Monthly	Once/Operating Cycle	None

PNPS
TABLE 4.2.B (Cont)

MINIMUM TEST AND CALIBRATION FREQUENCY FOR CSCS

Logical System Functional Test (4) (6)	Frequency	Remarks
1) Core Spray Subsystem	Once/Operating Cycle	
2) Low Press. Coolant Injection Subsystem	Once/Operating Cycle	
3) Containment Spray Subsystem	Once/Operating Cycle	
4) HPCI Subsystem	Once/Operating Cycle	
5) HPCI Subsystem Auto Isolation	Once/Operating Cycle	
6) ADS Subsystem	Once/Operating Cycle	
7) RCIC Subsystem Auto Isolation	Once/Operating Cycle	
8) Diesel Generator Initiation	Once/Operating Cycle	
9) Area Cooling for Safeguard System	Once/Operating Cycle	

TABLE 4.2.C

MINIMUM TEST AND CALIBRATION FREQUENCY FOR CONTROL ROD BLOCKS ACTUATION

Instrument Channel	Instrument Functional Test	Calibration	Instrument Check
RBM - Upscale	Once/3 Months	Once/6 Months	Once/Day
RBM - Downscale	Once/3 Months	Once/6 Months	Once/Day
RBM - Inoperative	Once/3 Months	Not Applicable	Once/Day
Mode Switch in Shutdown	Once/Operating Cycle	Not Applicable	Not Applicable
Logic System Functional Test (4) (6)			
System Logic Check	Once/Operating Cycle		

TABLE 4.2.D

MINIMUM TEST AND CALIBRATION FREQUENCY FOR RADIATION MONITORING SYSTEMS

	Instrument Channels	Instrument Functional Test	Calibration	Instrument Check
1)	Refuel Area Exhaust Monitors - Upscale	(1)	Once/3 months	Once/day
2)	Refuel Area Exhaust Monitors - Downscale	(1)	Once/3 months	Once/day

	Logic System Functional Test (4) (6)	Frequency
1)	Reactor Building Isolation	Once/Operating Cycle
2)	Standby Gas Treatment System Actuation	Once/Operating Cycle

PNPS

TABLE 4.2.F

MINIMUM TEST AND CALIBRATION FREQUENCY FOR SURVEILLANCE INSTRUMENTATION

Instrument Channel	Calibration Frequency	Instrument Check
1) Reactor Water Level	Each Refueling Outage	Each Shift
2) Reactor Pressure	Each Refueling Outage	Each Shift
3) Drywell Pressure	Each Refueling Outage	Each Shift
4) Drywell Temperature	Once/6 Months	Each Shift
5) Suppression Chamber Temperature	Once/6 Months	Each Shift
6) Suppression Chamber Water Level	Once/6 Months	Each Shift
7) NA		
8) Neutron Monitoring	(2)	Each Shift
9) Drywell/Torus Differential Pressure	Once/6 Months	Each Shift
10) Drywell Pressure Torus Pressure	Once/6 Months Once/6 Months	Each Shift
11) Safety/Relief Valve Position Indicator (Primary/Secondary)	Each refueling outage	Once each day
12) Safety Valve Position Indicator (Primary/ Secondary)	Each refueling outage	Once each day

PNPS
TABLE 4.2.F (Cont)

MINIMUM TEST AND CALIBRATION FREQUENCY FOR SURVEILLANCE INSTRUMENTATION

	Instrument Channel	Calibration Frequency	Instrument Check
13)	Torus Water Level (Wide Range)	Each refueling outage	Once every 30 days
14)	Containment Pressure	Each refueling outage	Once every 30 days
15)	Containment High Radiation Monitor	Once/Operating Cycle	Once every 30 days
16)	Reactor Building Vent Radiation Monitor	Once/Operating Cycle	Once every 30 days
17)	Main Stack Vent Radiation Monitor	Once/Operating Cycle	Once every 30 days
18)	Turbine Building Vent Radiation Monitor	Once/Operating Cycle	Once every 30 days

PNPS
TABLE 4.2.G

MINIMUM TEST AND CALIBRATION FREQUENCY FOR ATWS RPT/ARI INSTRUMENTATION

Instrument Channel	Instrument Functional Test	Calibration	Instrument Check
1. Reactor High Pressure	(1) (7)	(7)	Once/day
2. Reactor Low-Low Water Level	(1) (7)	(7)	Once/day

PNPS
TABLE 4.2.H

MINIMUM TEST & CALIBRATION FREQUENCY FOR DRYWELL TEMPERATURE SURVEILLANCE INSTRUMENTATION

Instrument Channels/ Nominal Elevation	Calibration Frequency	Instrument Check
80 Feet	Each Refueling Outage	Once per Shift
87 Feet	Each Refueling Outage	Once per Shift
60 Feet	Each Refueling Outage	Once per Shift
41 Feet	Each Refueling Outage	Once per Shift
32 Feet	Each Refueling Outage	Once per Shift

NOTES FOR TABLES 4.2.A THROUGH 4.2.G

1. Initially once per month until exposure hours (M as defined on Figure 4.2-1) is 2.0×10^5; thereafter, according to Figure 4.2-1 with an interval not less than one month nor more than three months.

2. Calibrations of IRMs and SRMs shall be performed during each startup or during controlled shutdowns with a required frequency not to exceed once per week.

3. Deleted.

4. Simulated automatic actuation shall be performed once each operating cycle. Where possible, all logic system functional tests will be performed using the test jacks.

5. Reactor low water level and high drywell pressure are not included on Table 4.2.A since they are tested on Tables 4.1.1 and 4.1.2.

6. The logic system functional tests shall include a calibration of time delay relays and timers necessary for proper functioning of the trip systems.

7. Calibration of analog trip units will be performed concurrent with functional testing. The functional test will consist of injecting a simulated electrical signal into the measurement channel. Calibration of associated analog transmitters will be performed each refueling outage.

LIMITING CONDITIONS FOR OPERATION

3.3 REACTIVITY CONTROL

A. Reactivity Margin - Core Loading

LCO 3.3.A.1

The core loading shall be limited to that which can be made subcritical in the most reactive condition during the OPERATING CYCLE with the strongest OPERABLE control rod in its full-out position and all other OPERABLE rods fully inserted.

APPLICABILITY:

At all times when there is fuel in the reactor vessel.

ACTIONS:

A. LCO 3.3.A.1 cannot be met.

1 Be in HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.3 REACTIVITY CONTROL

A. Reactivity Margin - Core Loading

SR 4.3.A.1

Sufficient control rods shall be withdrawn following a REFUELING OUTAGE when CORE ALTERATIONS were performed to demonstrate with a margin of 0.25 percent Δk that the core can be made subcritical at any time in the subsequent fuel cycle with the strongest OPERABLE control rod fully withdrawn and all other OPERABLE rods fully inserted.

LIMITING CONDITIONS FOR OPERATION

3.3 REACTIVITY CONTROL (continued)

B. Control Rod Operability

LCO 3.3.B.1

Each control rod shall be OPERABLE.

APPLICABILITY:

RUN and STARTUP MODES; REFUEL MODE when the reactor vessel head is fully tensioned. (See also 3/4.14.E)

ACTIONS

----------------NOTE--------------------
Separate condition entry is allowed for each control rod.

A. One withdrawn control rod stuck.

------------------NOTE------------------
Rod Worth Minimizer (RWM) may be bypassed as allowed by LCO 3.3.F.
----

1. Verify stuck control rod separation criteria are met immediately.

AND

2. Disarm the associated control rod drive (CRD) within 2 hours.

AND

3. Perform SR 4.3.B.1.1 and SR 4.3.B.1.2 for each withdrawn OPERABLE control rod within 24 hours from discovery of condition A concurrent with thermal power greater than the Low Power Setpoint (LPSP) of the RWM.

AND

4. Verify LCO 3.3.A.1 is met within 72 hours.

AND

SURVEILLANCE REQUIREMENTS

4.3 REACTIVITY CONTROL (continued)

B. Control Rod Operability

SR 4.3.B.1.1

----------------------NOTE----------------------
Not required to be performed until 7 days after the control rod is withdrawn and thermal power is greater than the LPSP of the RWM.

Insert each fully withdrawn OPERABLE control rod at least one notch once per 7 days.

SR 4.3.B.1.2

----------------------NOTE----------------------
Not required to be performed until 31 days after the control rod is withdrawn and thermal power is greater than the LPSP of the RWM.

Insert each partially withdrawn OPERABLE control rod at least one notch once per 31 days.

SR 4.3.B.1.3

Verify each withdrawn control rod does not go to the withdrawn overtravel position.

a. Each time the control rod is withdrawn to "full out" position.

AND

b. Prior to declaring control rod OPERABLE after work on control rod or CRD system that could affect coupling.

SR 4.3.B.1.4

Verify each control rod scram time from fully withdrawn to notch position 04 is $\leq$ 7 seconds in accordance with SR 4.3.C.1, SR 4.3.C.2, SR 4.3.C.3 or SR 4.3.C.4

SR 4.3.B.1.5

Determine the position of each control rod once per 24 hours.

LIMITING CONDITIONS FOR OPERATION | **SURVEILLANCE REQUIREMENTS**

3.3 REACTIVITY CONTROL (continued) | 4.3 REACTIVITY CONTROL (continued)

B. Control Rod Operability (continued) | B. Control Rod Operability (continued)

LCO 3.3.B.1 (continued)

5. -------------NOTE-------------
   Not applicable when thermal power > 20% RTP.

   Ensure stuck rod is in compliance with banked position withdrawal sequence (BPWS) within 8 hours.

   OR

   Verify control rod drop accident limit of 280 cal/gm is not exceeded within 8 hours.

B. Two or more withdrawn control rods stuck.

1. Be in HOT SHUTDOWN within 12 hours.

C. One or more control rods inoperable for reasons other than condition A or B.

1. --------------NOTE------------
   RWM may be bypassed as allowed by LCO 3.3.F.

   Fully insert inoperable control rod within 3 hours.

AND

2. Disarm the associated CRD within 4 hours.

LIMITING CONDITIONS FOR OPERATION

3.3 REACTIVITY CONTROL (continued)

B. Control Rod Operability (continued)

LCO 3.3.B.1 (continued)

D. ------------------NOTE------------------
Not applicable when thermal power > 20% RTP.

Two or more inoperable control rods not in compliance with BPWS and not separated by two or more OPERABLE control rods.

1. Restore compliance with BPWS within 8 hours.

<u>OR</u>

2. Verify control rod drop accident limit of 280 cal/gm is not exceeded within 8 hours.

<u>OR</u>

3. Restore control rod(s) to OPERABLE status within 8 hours.

E. ------------------NOTE------------------
Not applicable when thermal power > 20% RTP.

One or more groups with four or more inoperable control rods.

1. Restore control rod(s) to OPERABLE status within 8 hours.

F. Required action and associated completion time of condition A, C, D, or E not met.

<u>OR</u>

Nine or more control rods inoperable.

1. Be in HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.3 REACTIVITY CONTROL (continued)

B. Control Rod Operability (continued)

B. Control Rod Operability (continued)

LCO 3.3.B.2

The control rod drive housing support system shall be in place.

APPLICABILITY:

During reactor power operation and when the reactor coolant system is pressurized above atmospheric pressure with fuel in the reactor vessel.

ACTIONS:

A. LCO 3.3.B.2 cannot be met.

1 Be in COLD SHUTDOWN within 24 hours.

B. Control Rod Operability (continued)

SR 4.3.B.2

The control rod drive housing support system shall be inspected after reassembly and the results of the inspection recorded.

LIMITING CONDITIONS FOR OPERATION

3.3 REACTIVITY CONTROL (continued)

B. Control Rod Operability (continued)

LCO 3.3.B.3

Control rods shall not be withdrawn for startup unless at least two source range channels have an observed count rate equal to or greater than three counts per second.

APPLICABILITY:

Prior to withdrawing control rods for startup.

ACTIONS:

A. LCO 3.3.B.3 cannot be met.

1. Place the mode switch in shutdown immediately.

SURVEILLANCE REQUIREMENTS

4.3 REACTIVITY CONTROL (continued)

B. Control Rod Operability (continued)

SR 4.3.B.3

Prior to control rod withdrawal for startup, verify that at least two source range channels have an observed count rate of at least three counts per second.

LIMITING CONDITIONS FOR OPERATION

3.3 REACTIVITY CONTROL (continued)

C. Control Rod Scram Times

LCO 3.3.C

1. No more than 10 OPERABLE control rods shall be "slow," in accordance with Table 3.3.C-1, and

2. No more than 2 OPERABLE control rods that are "slow" shall occupy adjacent locations.

APPLICABILITY:

RUN and STARTUP MODES; REFUEL MODE when the reactor vessel head is fully tensioned.

ACTIONS:

A. LCO 3.3.C cannot be met.

   1. Be in HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.3 REACTIVITY CONTROL (continued)

C. Control Rod Scram Times

--------------------NOTE--------------------

During single control rod scram time Surveillances, the control rod drive (CRD) pumps shall be isolated from the associated scram accumulator.

SR 4.3.C.1

Verify each control rod scram time is within the limits of Table 3.3.C-1 with reactor steam dome pressure $\geq$ 800 psig prior to exceeding 40% RTP after each reactor shutdown $\geq$ 120 days.

SR 4.3.C.2

Verify for a representative sample, each tested control rod scram time is within the limits of Table 3.3.C-1 with reactor steam dome pressure $\geq$ 800 psig within each 200 days of cumulative operation in RUN.

SR 4.3.C.3

Verify each affected control rod scram time is within the limits of Table 3.3.C-1 with any reactor steam dome pressure prior to declaring control rod OPERABLE after work on control rod or CRD System that could affect scram time.

SR 4.3.C.4

Verify each affected control rod scram time is within the limits of Table 3.3.C-1 with reactor steam dome pressure $\geq$ 800 psig prior to exceeding 40% RTP after fuel movement within the affected core cell AND prior to exceeding 40% RTP after work on control rod or CRD System that could affect scram time.

Table 3.3.C-1 (page 1 of 1)
Control Rod Scram Times

-----NOTES-----

1. OPERABLE Control Rods with scram times not within the limits of this Table are considered "slow."
2. Enter applicable Conditions and Required Actions of LCO 3.3.B, "Control Rod OPERABILITY," for control rods with scram times > 7 seconds to notch position 04. These control rods are inoperable, in accordance with SR 4.3.B.1.4, and are not considered "slow."

NOTCH POSITION	SCRAM TIMES [a][b] (seconds) WHEN REACTOR STEAM DOME PRESSURE $\geq$ 800 PSIG
44	0.57
34	1.23
24	1.99
04	3.51

a) Maximum scram time from fully withdrawn position, based on de-energization of scram pilot valve solenoids at time zero.

b) Scram times as a function of reactor steam dome pressure, when < 800 psig are within established limits.

LIMITING CONDITIONS FOR OPERATION

3.3 REACTIVITY CONTROL (continued)

D. Control Rod Scram Accumulators

LCO 3.3.D

Each control rod scram accumulator shall be OPERABLE.

APPLICABILITY:

RUN and STARTUP MODES;
REFUEL MODE when the reactor vessel head is fully tensioned.

ACTIONS:

------------------NOTE--------------------
Separate condition entry is allowed for each control rod scram accumulator.

A. One control rod scram accumulator inoperable with reactor steam dome pressure ≥ 950 psig.

1.--------------NOTE-----------------

Only applicable if the associated control rod scram time was within limits of Table 3.3.C-1 during the last scram time surveillance.

Declare the associated control rod scram time "slow" within 8 hours.

OR

2. Declare the associated control rod inoperable within 8 hours.

B. Two or more control rod scram accumulators inoperable, with reactor steam dome pressure ≥ 950 psig.

1. Restore charging water header pressure to ≥ 940 psig within 20 minutes from discovery of inoperable accumulators with charging water header < 940 psig.

AND

SURVEILLANCE REQUIREMENTS

4.3 REACTIVITY CONTROL (continued)

D. Control Rod Scram Accumulators

SR 4.3.D

Verify each control rod scram accumulator pressure is ≥ 940 psig every 7 days.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.3 REACTIVITY CONTROL (continued)	4.3 REACTIVITY CONTROL (continued)
D. Control Rod Scram Accumulators (continued)	D. Control Rod Scram Accumulators (continued)

LCO 3.3.D (continued)

2.1 -------------NOTE-------------
Only applicable if the associated control rod scram time was within limits of Table 3.3.C-1 during the last scram time surveillance.

Declare the associated control rod scram time "slow" within 1 hour.

OR

2.2 Declare the associated control rod inoperable within 1 hour.

C. One or more control rod scram accumulators inoperable, with reactor steam dome pressure < 950 psig.

1. Verify all control rods associated with inoperable accumulators are fully inserted immediately upon discovery of charging water header pressure < 940 psig.

AND

2. Declare the associated control rod inoperable within 1 hour.

D. Required action and associated completion time if B.1 or C.1 not met.

1. -------------NOTE-------------
Not applicable if all inoperable control rod scram accumulators are associated with fully inserted control rods.

Place the reactor mode switch in the shutdown position immediately.

E. Reactivity Anomalies

LCO 3.3.E

The reactivity equivalent of the difference between the actual critical rod configuration and the expected configuration shall not exceed 1% ΔK.

APPLICABILITY:

STARTUP AND RUN MODES

ACTIONS:

A. Limit exceeded.

1 Be in HOT SHUTDOWN within 12 hours.

E. Reactivity Anomalies

SR 4.3.E

During startups following REFUELING OUTAGES, the critical rod configurations will be compared to the expected configurations at selected operating conditions. These comparisons will be used as base data for reactivity monitoring during subsequent power operation throughout the fuel cycle. At specific power operating conditions, the critical rod configuration will be compared to the configuration expected based upon appropriately corrected past data. This comparison will be made at least every full power month.

LIMITING CONDITIONS FOR OPERATION

3.3 REACTIVITY CONTROL (Continued)

F. Rod Worth Minimizer (RWM)

LCO 3.3.F

The RWM shall be OPERABLE.

APPLICABILITY:

RUN and STARTUP MODES with reactor thermal power ≤ 20% RTP.

ACTIONS:

A. RWM inoperable during reactor startup.

1 Immediately suspend control rod movement except by scram.

OR

2.1.1 Immediately verify ≥ 12 rods withdrawn,

OR

2.1.2 Immediately verify by administrative methods that startup with RWM inoperable has not been performed in the last calendar year.

AND

2.2 Verify movement of control rods is in compliance with BPWS by a second licensed operator or other qualified member of the technical staff during control rod movement.

B. RWM inoperable during reactor shutdown.

1 Verify movement of control rods is in accordance with BPWS by a second licensed operator or other qualified member of the technical staff during control rod movement.

SURVEILLANCE REQUIREMENT

4.3 REACTIVITY CONTROL (Continued)

F. Rod Worth Minimizer (RWM)

SR 4.3.F.1

Perform an INSTRUMENT FUNCTIONAL TEST of the RWM prior to control rod withdrawal for startup or insertion to reduce power below 20%.

SR 4.3.F.2

Verify the RWM automatic bypass setpoint to be > 20% RTP every 24 months.

SR 4.3.F.3

Verify control rod sequences input to the RWM are in conformance with BPWS prior to declaring RWM OPERABLE following loading of sequence into RWM.

LIMITING CONDITION FOR OPERATION

3.3 REACTIVITY CONTROL (continued)

G. Scram Discharge Volume (SDV)

LCO 3.3.G

The scram discharge volume drain & vent valves shall be OPERABLE.

APPLICABILITY:

RUN and STARTUP MODES; REFUEL MODE when the reactor vessel head is fully tensioned.

ACTIONS:

------------ NOTE ---------------
ACTIONS may be applied independently to each vent or drain line.

A. With one or more SDV vent or drain lines with one valve inoperable, isolate* the associated line within 7 days.

B. One or more SDV vent or drain lines with both valves inoperable, isolate* the associated line within 8 hours.

C. Otherwise, be in HOT SHUTDOWN within the next 12 hours.

(*) An isolated line may be unisolated under administrative control to allow draining and venting of the SDV.

SURVEILLANCE REQUIREMENTS

4.3 REACTIVITY CONTROL (continued)

G. Scram Discharge Volume (SDV)

SR 4.3.G.1

Verify scram discharge volume drain and vent valves open at least once per month.

SR 4.3.G.2

Test scram discharge volume drain and vent valves as specified in 4.13. These valves may be closed intermittently for testing under administrative control.

SR 4.3.G.3

During each REFUELING INTERVAL verify the scram discharge volume drain and vent valves.

a. Close within 30 seconds after receipt of a reactor scram signal.

AND

b. Open when the scram is reset.

H. Rod Pattern Control

LCO 3.3.H

All OPERABLE control rods shall comply with the requirements of the BPWS.

APPLICABILITY:

RUN and STARTUP MODES with reactor thermal power ≤ 20 % RTP.

ACTIONS:

A. One or more OPERABLE control rods not in compliance with BPWS.

1 ------------NOTE-------------
RWM may be bypassed as allowed by LCO 3.3.F.

Move associated control rod(s) to correct position within 8 hours.

OR

2 Verify control rod drop accident limit of 280 cal/gm is not exceeded within 8 hours.

OR

3 Declare associated control rod(s) inoperable within 8 hours.

(continued)

H. Rod Pattern Control

SR 4.3.H

Verify all OPERABLE control rods comply with BPWS every 24 hours.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.3 REACTIVITY CONTROL (continued)	4.3 REACTIVITY CONTROL (continued)

H. Rod Pattern Control (continued)

LCO 3.3.H (continued)

B. Nine or more OPERABLE control rods not in compliance with BPWS.

1. ------------NOTE-------------
RWM may be bypassed as allowed by LCO 3.3.F.

Immediately suspend withdrawal of control rods.

AND

2. Place the reactor mode switch in the shutdown position within 1 hour.

H. Rod Pattern Control (continued)

LIMITING CONDITIONS FOR OPERATION

3.4 STANDBY LIQUID CONTROL SYSTEM

Specification:

Two SLC subsystems shall be OPERABLE.

Applicability:

Run and Startup MODES

Operation with Inoperable Equipment

A. With concentration of boron in solution not within limits but > 8%, restore concentration of boron in solution to within limits within 72 hours AND 10 days from discovery of failure to meet the LCO.

B. With one SLC subsystem inoperable for reasons other than Condition A,

1. ensure that the diesel generator associated with the operable SLC subsystem is operable;

AND

2. restore SLC subsystem to OPERABLE status within 7 days AND 10 days from discovery of failure to meet the LCO.

C. With two SLC subsystems inoperable for reasons other than Condition A, restore one SLC subsystem to OPERABLE status within 8 hours.

D. Required Action and associated Completion Time not met, be in Hot Shutdown within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4 STANDBY LIQUID CONTROL SYSTEM

1. When tested as specified in 3.13 verify that each pump delivers at least 39 GPM against a system head of 1275 psig.
2. Manually initiate one of the Standby Liquid Control System loops and pump demineralized water into the reactor vessel every 24 months on a STAGGERED TEST BASIS.
3. Verify continuity of explosive charge every 31 days.
4. Verify available volume of sodium pentaborate solution is within the limits of Figure 3.4-1 or ≥ 4000 gallons every 24 hours.
5. Verify temperature of sodium pentaborate solution is > 48° F every 24 hours.
6. Verify the concentration of boron in solution is ≤ 9.22 % weight and within the limits of Figure 3.4-1 every 31 days;

   AND

   Once within 24 hours after water or boron is added to solution;

   AND

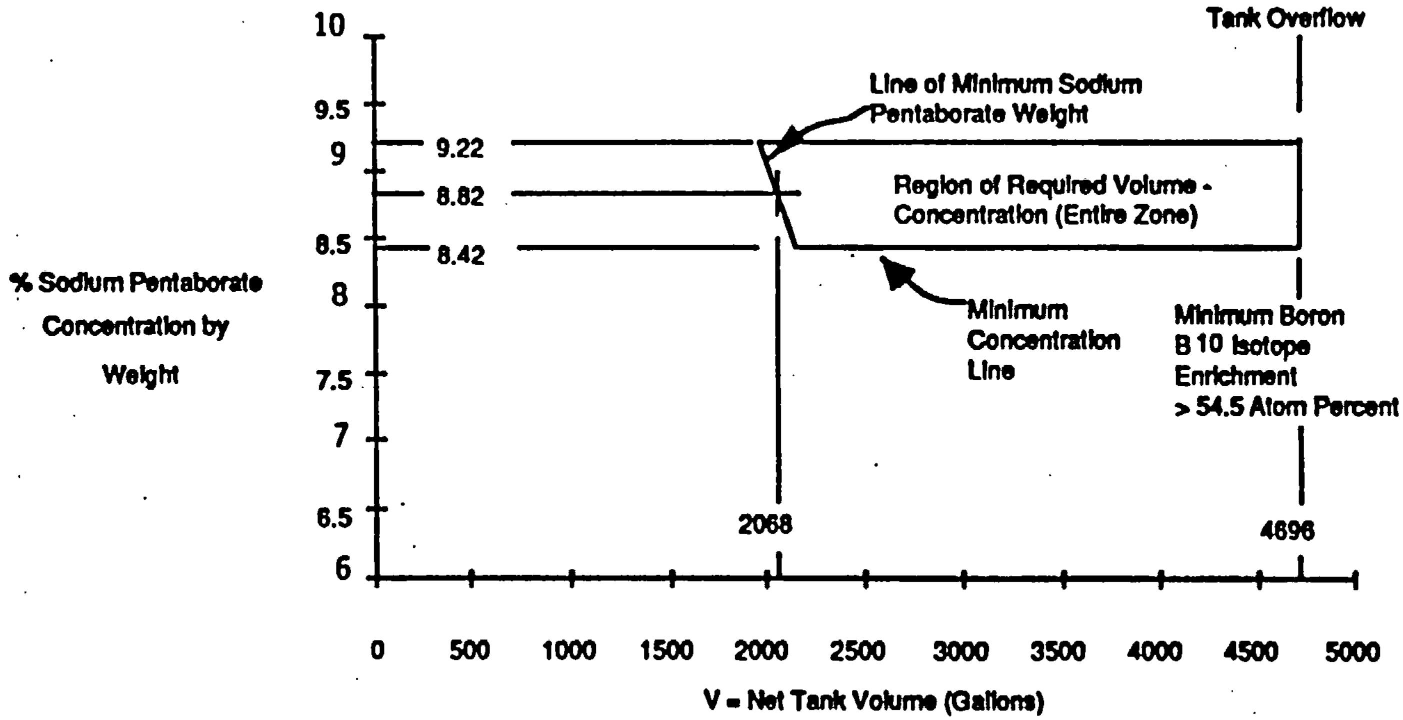
   Once within 24 hours after solution temperature is restored to > 48° F.
7. Verify sodium pentaborate enrichment is ≥ 54.5 atom percent B-10 prior to addition to SLC tank.
8. Verify all heat traced piping between storage tank and pump suction is unblocked every 24 months.

   AND

   Once within 24 hours after solution temperature is restored to > 48° F.
9. Verify temperature of pump suction piping is > 48° F every 24 hours.

PNPS
Figure 3.4-1

Sodium Pentaborate Solution
Volume and Concentration Requirements



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Amendment No. ~~102~~ ,169
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3.5 CORE AND CONTAINMENT COOLING SYSTEMS

Applicability

Applies to the operational status of the core and suppression pool cooling systems.

Objective

To assure the operability of the core and suppression pool cooling systems under all conditions for which this cooling capability is an essential response to station abnormalities.

Specification

A. Core Spray and LPCI Systems

1. Both core spray systems shall be Operable during Run, Startup, and Hot Shutdown Modes and prior to reactor startup from Cold Shutdown, except as specified in 3.5.A.2.

2. During Run, Startup, and Hot Shutdown Modes:

   a. With one of the core spray systems inoperable, restore the inoperable core spray system to Operable status within 7 days and maintain all active components of the LPCI system and the diesel generators Operable. Otherwise, be in at least Cold Shutdown within 24 hours.

   b. With both of the core spray systems inoperable be in at least Cold Shutdown within 24 hours.

3. The LPCI system shall be Operable during Run, Startup, and Hot Shutdown Modes and prior to reactor startup from Cold Shutdown, except as specified in 3.5.A.4.

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

Applicability

Applies to the Surveillance Requirements of the core and suppression pool cooling systems which are required when the corresponding Limiting Condition for operation is in effect.

Objective

To verify the operability of the core and suppression pool cooling systems under all conditions for which this cooling capability is an essential response to station abnormalities.

Specification

A. Core Spray and LPCI Systems

1. Core Spray System Testing.

Item	Frequency
a. Simulated Automatic Actuation Test.	Once/ Operating Cycle
b. Pump Operability.	When tested as specified in 3.13 verify that each core spray pump delivers at least 3300 GPM against a system head correspond-ing to a reactor vessel pressure of 104 psig.

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

A. Core Spray and LPCI Systems (Cont)

4. During Run, Startup, and Hot Shutdown Modes with the LPCI system inoperable, restore the LPCI system to Operable status within 7 days and maintain both core spray systems and the diesel generators Operable. Otherwise, be in at least Cold Shutdown within 24 hours.

5. Two low pressure injection/spray subsystems shall be Operable during Cold Shutdown and Refuel Modes unless the reactor head is removed, the spent fuel pool gates are removed, and water level is at greater than or equal to elevation 114 foot, except as specified in 3.5.A.6.

6. During Cold Shutdown and Refuel Modes unless the reactor head is removed, the spent fuel pool gates are removed, and water level is at greater than or equal to elevation 114 foot:

   a. With one of the required low pressure injection/spray subsystems inoperable, restore the inoperable required low pressure injection/spray subsystem to Operable status within 4 hours. Otherwise, take immediate action to suspend activities with potential for draining the reactor vessel.

   b. With both of the required low pressure injection/spray subsystems inoperable, take immediate action to suspend activities with potential for draining the reactor vessel and restore 1 low pressure injection/spray subsystem to Operable status within 4 hours. Otherwise, take immediate action to restore secondary containment and one standby gas treatment system to Operable status and to restore isolation capability in each required secondary containment penetration flow path not isolated.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

A. Core Spray and LPCI Systems (Cont)

1. c. Motor Operated Valve Operability — As Specified in 3.13

   d. Core Spray Header Δp Instrumentation

Check	Once/day
Calibrate	Once/3 months
Test Step	Once/3 months

2. This section intentionally left blank

3. LPCI system testing shall be as follows:

a. Simulated Automatic Actuation Test	Once/ Operating Cycle
b. Pump Operability.	When tested as specified in 3.13, verify that each LPCI pump delivers 4800 GPM at a head across the pump of at least 380 ft.
c. Motor Operated Valve Operability	As Specified in 3.13

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

B.1 Residual Heat Removal (RHR) Suppression Pool Cooling

Specification:

Two RHR suppression pool cooling subsystems shall be OPERABLE.

Applicability:

Whenever irradiated fuel is in the reactor vessel, reactor coolant temperature is >212° F, and prior to startup from a cold condition.

Actions:

A. One RHR suppression pool cooling subsystem inoperable,

   1. Restore the RHR suppression pool cooling subsystem to OPERABLE status within 7 days.

B. Required Action and associated Completion Time not met.

   OR

   More than two RHR pumps inoperable.

   OR

   Two RHR suppression pool cooling subsystems inoperable.

   1. Be in Cold Shutdown within 24 hours.

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

B.1 Residual Heat Removal (RHR) Suppression Pool Cooling

1. Verify each RHR suppression pool cooling subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position or can be aligned to the correct position every 31 days.

2. Verify each RHR pump develops a flow rate ≥ 5100 GPM through the associated heat exchanger while operating in the suppression pool cooling mode as specified in Specification 3/4.13.

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

B.2 Residual Heat Removal (RHR) Containment Spray

Specification:

Two RHR containment spray subsystems shall be OPERABLE.

Applicability:

Whenever irradiated fuel is in the reactor vessel, reactor coolant temperature is > 212°F, and prior to startup from a cold condition.

Actions:

A. One RHR containment spray subsystem inoperable,

   1. Restore RHR containment spray subsystem to OPERABLE status within 7 days.

B. Required Action and associated Completion Time not met

   OR

   Two RHR containment spray subsystems inoperable,

   1. Be in Cold Shutdown within 24 hours.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

B.2 Residual Heat Removal (RHR) Containment Spray

1. Verify each RHR containment spray subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position or can be aligned to the correct position every 31 days.

2. Air test drywell and suppression pool (torus) headers and nozzles following maintenance that could result in nozzle blockage.

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

B.3 Reactor Building Closed Cooling Water (RBCCW) System

Specification:

Two RBCCW subsystems shall be OPERABLE.

Applicability:

Whenever irradiated fuel is in the reactor vessel, reactor coolant temperature is >212° F, and prior to startup from a cold condition.

Actions:

A. One required RBCCW Pump Inoperable.

   1. Restore the required RBCCW pump to OPERABLE status within 7 days.

B. One RBCCW subsystem inoperable for reasons other than Condition A.

   1. Restore the RBCCW subsystem to OPERABLE status within 72 hours.

C. Required Action and associated Completion Times of Condition A or B not met.

   OR

   Two RBCCW subsystems inoperable.

   1. Be in Cold Shutdown within 24 hours.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

B.3 Reactor Building Closed Cooling Water (RBCCW) System

1. --------------------NOTE--------------------
   Isolation of flow to individual components does not render the RBCCW subsystem inoperable.

   Verify each RBCCW manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position every 31 days.

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

B.4 Salt Service Water (SSW)] System

Specification:

Two SSW subsystems shall be OPERABLE.

Applicability:

Whenever irradiated fuel is in the reactor vessel, reactor coolant temperature is >212° F, and prior to startup from a cold condition.

Actions:

A. One SSW subsystem inoperable,

1. Restore the SSW subsystem to OPERABLE status within 72 hours.

B. Required Action and associated Completion Time not met,

OR

Two SSW subsystems inoperable,

OR

UHS inoperable,

1. Be in Cold Shutdown within 24 hours.

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

B.4 Salt Service Water (SSW)] System

1. Verify the water level in each SSW pump well of the intake structure is ≥13 ft 9 in below mean sea level every 24 hours.

2. Verify the average sea water temperature is ≤ 75°F every 24 hours.

3. ————NOTE————
Isolation of flow to individual components does not render the SSW subsystem inoperable.

Verify each SSW subsystem manual, power operated, and automatic valve in the flow paths servicing safety related systems or components, that is not locked, sealed, or otherwise secured in position, is in the correct position every 31 days.

4. Verify each SSW subsystem actuates on an actual or simulated initiation signal every 2 years.

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

C. HPCI System

1. The HPCI system shall be operable whenever there is irradiated fuel in the reactor vessel, reactor pressure is greater than 150 psig., and reactor coolant temperature is greater than 365°F, except as specified in 3.5.C.2 below.

2. From and after the date that the HPCI system is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 14 days unless such system is sooner made operable, providing that during such 14 days all active components of the ADS system, the RCIC system, the LPCI system and both core spray systems are operable.

3. If the requirements of 3.5.C cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in the Cold Shutdown Condition within 24 hours.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

C. HPCI System

1. HPCI system testing shall be as follows:

a. Simulated Automatic Actuation Test	Once/ Operating Cycle

---------------------- Note ------------------

Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform test.

---

b. Pump Operability	When tested as specified in 3.13, verify with reactor pressure ≤1035 and ≥ 940 psig, the HPCI pump can develop a flow rate ≥ 4250 gpm against a system head corresponding to reactor pressure.
c. Motor Operated Valve Operability	As Specified in 3.13

---------------------- Note ------------------

Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform test.

---

d. Flow Rate at 150 psig.	Once/ Operating Cycle, verify with reactor pressure ≤ 150 psig, the HPCI pump can develop a flow rate ≥ 4250 gpm against a system head corresponding to reactor pressure.

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

D. Reactor Core Isolation Cooling (RCIC) System

1. The RCIC system shall be operable whenever there is irradiated fuel in the reactor vessel, reactor pressure is greater than 150 psig, and reactor coolant temperature is greater than 365°F, except as specified in 3.5.D.2 below.

2. From and after the date that the RCIC system is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 14 days unless such system is sooner made operable, providing that during such 14 days the HPCIS is operable.

3. If the requirements of 3.5.D cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in the Cold Shutdown Condition within 24 hours.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

D. Reactor Core Isolation Cooling (RCIC) System

1. RCIC system testing shall be as follows:

a. Simulated Automatic Actuation Test	Once/ Operating Cycle

---------------------- Note -----------------

Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform test.

----

b. Pump Operability	When tested as specified in 3.13, verify with reactor pressure ≤ 1035 and ≥ 940 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.
c. Motor Operability Valve Operability	As Specified in 3.13

---------------------- Note -----------------

Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform test.

----

d. Flow Rate at 150 psig.	Once/Operability Cycle verify with reactor pressure ≤ 150 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

E. Automatic Depressurization System (ADS)

1. The Automatic Depressurization System shall be operable whenever there is irradiated fuel in the reactor vessel and the reactor pressure is greater than 104 psig and prior to a startup from a Cold Condition, except as specified in 3.5.E.2 below.

2. From and after the date that one valve in the Automatic Depressurization System is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 14 days unless such valve is sooner made operable, provided that during such 14 days the HPCI system is operable.

3. If the requirements of 3.5.E cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in the Cold Shutdown Condition within 24 hours.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

E Automatic Depressurization System (ADS)

1. During each operating cycle the following tests shall be performed on the ADS:

   a. A simulated automatic actuation test shall be performed prior to startup after each refueling outage.

      The ADS manual inhibit switch will be included in this test.

   b. With the reactor at pressure, each relief valve shall be manually opened until a corresponding change in reactor pressure or main turbine bypass valve positions indicate that steam is flowing from the valve.

LIMITING CONDITION FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS (Cont)

F. Minimum Low Pressure Cooling and Diesel Generator Availability

1. During any period when one emergency diesel generator (EDG) is inoperable, continued reactor operation is permissible only during the succeeding 72 hours unless such EDG is sooner made operable, provided that all of the low pressure core and containment cooling systems shall be operable, and the remaining EDG shall be operable in accordance with 4.5.F.1. If this requirement cannot be met, an orderly shutdown shall be initiated and the reactor shall be placed in the Cold Shutdown Condition within 24 hours.

   The 72 hours LCO can be extended to 14 days provided, in addition to the above requirements, the Station Black Out Diesel Generator is verified operable in accordance with 4.5.F.2.

2. Deleted

3. Deleted

4. Deleted

SURVEILLANCE REQUIREMENT

4.5 CORE AND CONTAINMENT COOLING SYSTEMS (Cont)

F. Minimum Low Pressure Cooling and Diesel Generator Availability

1. When it is determined that one EDG is inoperable, within 24 hours, determine that the operable EDG is not inoperable due to a common cause failure,

   OR

   perform surveillance 4.9.A.1.a for the operable EDG,

   AND

   within 1 hour and once every 8 hours thereafter, verify correct breaker alignment and indicated power availability for each offsite circuit.

2. Confirm the Station Black Out Diesel Generator (SBO-DG) has been demonstrated operable within the preceding 7 days

   OR

   within 72 hours of declaring an EDG inoperable, perform a surveillance to demonstrate that the SBO-DG is operable,

   AND

   within 1 hour of demonstrating the SBO-DG operability as specified above and once every 8 hours thereafter, verify normal breaker configuration.

F Minimum Low Pressure Cooling and Diesel Generator Availability (Cont)

5. When irradiated fuel is in the reactor vessel and the reactor is in the Refueling Condition with the torus drained, a single control rod drive mechanism may be removed, if both of the following conditions are satisfied:

   a) No work on the reactor vessel, in addition to CRD removal, will be performed which has the potential for exceeding the maximum leak rate from a single control blade seal if it became unseated.

   b) i) the core spray systems are operable and aligned with a suction path from the condensate storage tanks. ii) the condensate storage tanks shall contain at least 200,000 gallons of usable water and the refueling cavity and dryer/separator pool shall be flooded to a least elevation 114'-0"

G. Deleted

F. Minimum Low Pressure Cooling and Diesel Generator Availability (Cont)

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

H. Maintenance of Filled Discharge Pipe

Whenever core spray systems, LPCI system, HPCI or RCIC are required to be operable, the discharge piping from the pump discharge of these systems to the last block valve shall be filled.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

H. Maintenance of Filled Discharge Pipe

The following surveillance requirements assure that the discharge piping of the core spray systems, LPCI system, HPCI and RCIC are filled:

1. Every month the LPCI system and core spray system discharge piping shall be vented from the high point and water flow observed.

2. Following any period where the LPCI system or core spray systems have not been required to be operable, the discharge piping of the inoperable system shall be vented from the high point prior to the return of the system to service.

3. Whenever the HPCI or RCIC system is lined up to take suction from the torus, the discharge piping of the HPCI and RCIC shall be vented from the high point of the system and water flow observed on a monthly basis.

LIMITING CONDITION FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY

Applicability:

Applies to the operating status of the reactor coolant system.

Objective:

To assure the integrity and safe operation of the reactor coolant system.

Specification:

A. **Thermal and Pressurization Limitations**

1. The average rate of reactor coolant temperature change during normal heatup or cooldown shall not exceed the limit in the PTLR.

2. The reactor vessel shall not be pressurized for hydrostatic and/or leakage tests, and subcritical or critical core operation shall not be conducted unless the reactor vessel temperatures are above those defined by the appropriate curves in the PTLR.

SURVEILLANCE REQUIREMENT

4.6 PRIMARY SYSTEM BOUNDARY

Applicability:

Applies to the periodic examination and testing requirements for the reactor cooling system.

Objective:

To determine the condition of the reactor coolant system and the operation of the safety devices related to it.

Specification

A. **Thermal and Pressurization Limitations**

1. During heatups and cooldowns, with the reactor vessel temperature less than or equal to 450°F, verify the RCS heatup and cooldown rates are within limits every 15 minutes.

2. Reactor vessel shell temperatures, including reactor vessel bottom head, and reactor coolant pressure shall be permanently logged at least every 15 minutes whenever the shell temperature is below 220°F and the reactor vessel is not vented.

LIMITING CONDITION FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

A. Thermal and Pressurization Limitations (Cont)

In the event this requirement is not met, achieve stable reactor conditions with reactor vessel temperature above that defined by the appropriate curve and obtain an engineering evaluation to determine the appropriate course of action to take.

3. The reactor vessel head bolting studs shall not be under tension unless the temperature of the vessel head flange and the head is greater than the PTLR limit.

4. The pump in an idle recirculation loop shall not be started unless the temperatures of the coolant within the idle and operating recirculation loops are within the PTLR limits.

5. The reactor recirculation pumps shall not be started unless the coolant temperatures between the dome and the bottom head drain are within the PTLR limits.

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

A. Thermal and Pressurization Limitations (Cont)

3. When the reactor vessel head bolting studs are tensioned and the reactor is in a Cold Condition, the reactor vessel shell temperature immediately below the head flange shall be permanently recorded.

4. Prior to and during startup of an idle recirculation loop, the temperature of the reactor coolant in the operating and idle loops shall be permanently logged.

5. Prior to starting a recirculation pump, the reactor coolant temperatures in the dome and in the bottom head drain shall be compared and permanently logged.

LIMITING CONDITION FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

B. Coolant Chemistry

1. The reactor coolant system radioactivity concentration in water shall not exceed 20 microcuries of total iodine per ml of water.

2. If Specification 3.6.B cannot be met, an orderly shutdown shall be initiated and the reactor shall be in Hot Shutdown within 24 hrs. and Cold Shutdown within the next 8 hours.

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

B. Coolant Chemistry

1. a. A reactor coolant sample shall be taken at least every 96 hours and analyzed for radioactivity content.

   b. Isotopic analysis of a reactor coolant sample shall be made at least once per month.

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

C. Coolant Leakage

Any time irradiated fuel is in the reactor vessel and coolant temperature is above 212°F, the following limits shall be observed:

1. Operational Leakage

   a. Reactor coolant system leakage shall be limited to:

      1. No Pressure Boundary Leakage

      2. ≤5 gpm Unidentified Leakage

      3. ≤25 gpm Total Leakage averaged over any 24 hour period.

      4. ≤2 gpm increase in Unidentified Leakage within any 24 hour period when in RUN mode.

   b. With any reactor coolant system leakage greater than the limits of 2. and/or 3., above, reduce the leakage to within acceptable limits within 4 hours or be in at least Hot Shutdown within the next 12 hours and in Cold Shutdown within the following 24 hours.

   c. With any reactor coolant system leakage greater than the limits of 4. above, identify the source of leakage within 4 hours or be in at least Hot Shutdown within the next 12 hours and in Cold Shutdown within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

C. Coolant Leakage

Any time irradiated fuel is in the reactor vessel and coolant temperature is above 212°F, the following surveillances shall be performed:

1. Operational Leakage

   Demonstrate drywell leakage is within the limits specified in 3.6.C.1 at least once every 8 hours.

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

C. Coolant Leakage (Cont)

d. When any Pressure Boundary Leakage is detected be in at least Hot Shutdown within the next 12 hours and be in Cold Shutdown within the next 24 hours.

2. Leakage Detection Systems

a. The following reactor coolant system leakage detection systems shall be Operable:

1. The drywell floor drain sump monitoring system, and either

2. One channel of a drywell atmospheric particulate radioactivity monitoring system, or

3. One channel of a drywell atmospheric gaseous radioactivity monitoring system.

b. 1. With the drywell floor drain monitoring system required by 3.6.C.2.a.1 inoperable, restore it to Operable status within 30 days, otherwise, be in Hot Shutdown within the next 12 hours and in Cold Shutdown within the following 24 hours.

2. With both the gaseous and particulate radioactivity monitoring channels required by 3.6.C.2.a.2 and 3.6.C.2.a.3 inoperable, reactor operation may continue for up to 30 days provided drywell atmosphere grab samples are analyzed every 12 hours, otherwise, be in Hot Shutdown within the next 12 hours and in Cold Shutdown within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

C. Coolant Leakage (Cont)

2. Leakage Detection Systems

The following reactor coolant leakage detection systems shall be demonstrated Operable:

a. For the drywell floor drain sump monitoring system perform:

1. An instrument functional test at least once per 31 days, and

2. An instrument channel calibration at least once per operating cycle.

b. For each required drywell atmospheric radioactivity monitoring system perform:

1. An instrument check at least once every 12 hours,

2. An instrument functional test at least once per 31 days, and

3. An instrument channel calibration at least once per operating cycle.

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

c. With no required leakage detection systems Operable, be in Hot Shutdown within the next 12 hours and in Cold Shutdown within the following 24 hours.

D. Safety and Relief Valves

1. During reactor power operating conditions and prior to reactor startup from a Cold Condition, or whenever reactor coolant pressure is greater than 104 psig and temperature greater than 340°F, both safety valves and the safety modes of all relief valves shall be operable.

2. If Specification 3.6.D.1 is not met, an orderly shutdown shall be initiated and the reactor coolant pressure shall be below 104 psig within 24 hours.

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

D. Safety and Relief Valves

1. As specified in accordance with 3.13, verify the safety function lift setpoints of the safety and relief valves as follows:

No. of S/R Valves	Setpoint (psig)
2 Safety	1280 ± 38.4
4 Relief	1155 ± 34.6

Following testing, lift setting shall be within ± 1%.

---------------- Note ------------------

Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform test.

----

2. Once/ Operating Cycle, verify each relief valve opens when manually actuated.

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

E. Jet Pumps

1. Whenever the reactor is in the Startup or Run Modes, all jet pumps shall be Operable. If it is determined that a jet pump is inoperable, the reactor shall be in Hot Shutdown within 12 hours.

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

E. Jet Pumps

NOTES

1. Not required to be performed until 4 hours after the associated recirculation loop is in operation.
2. Not required to be performed until 24 hours after >25% Rated Thermal Power.

Whenever there is recirculation flow with the reactor in the Startup or Run Modes, jet pump operability shall be checked daily by verifying at least one of the following criteria (1, 2, or 3) is satisfied for each operating recirculation loop:

1. Recirculation pump flow to speed ratio differs by ≤ 5% from established patterns, and jet pump loop flow to recirculation pump speed ratio differs by ≤ 5% from established patterns.
2. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns.
3. Each jet pump flow differs by ≤ 10% from established patterns.

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

F. Recirculation Loops Operating

During operation in the Run and Startup Modes, at least one recirculation pump shall be operating.

1. Whenever both recirculation pumps are in operation, pump speeds shall be maintained within 10% of each other when power level is greater than 80% and within 15% of each other when power level is less than or equal to 80%.
2. Whenever a single recirculation loop is operating, the following limits are applied when the associated LCO is applicable:
   a) LCO 3.11.A, "Average Planar Linear Heat Generation Rate (APLHGR)," single loop operation limits specified in the COLR,
   b) LCO 3.11.C, "Minimum Critical Power Ratio (MCPR)," single loop operation limits specified in the COLR, and
   c) LCO 3.1, "Reactor Protection System," Average Power Range Monitor High Flux function, trip level setting for the flow bias function is reset for single loop operation per Table 3.1.1.
3. If the requirements of Specification 3.6.F.1 or 3.6.F.2 are not met, restore compliance within 24 hours. If compliance is not restored or with no recirculation pumps in operation the reactor shall be in Hot Shutdown within 12 hours.

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

F. Recirculation Loops Operating

Recirculation pump speeds shall be checked and logged at least once per day.

Pilgrim Reactor Vessel Pressure-Temperature Limits Hydrostatic and Leak Rates

is Relocated to PTLR and TS 5.5.9

Pilgrim Reactor Vessel Pressure-Temperature Limits Subcritical Heat up and Cool down

is Relocated to PTLR and TS 5.5.9

Pilgrim Reactor Vessel Pressure-Temperature Limits Critical Core Operation

is Relocated to PTLR and TS 5.5.9

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS

Applicability:

Applies to the operating status of the primary and secondary containment systems.

Objective:

To assure the integrity of the primary and secondary containment systems.

Specification:

A. Primary Containment

Suppression Pool

1. At any time that the nuclear system is pressurized above atmospheric pressure or work is being done which has the potential to drain the vessel, the pressure suppression pool water volume and temperature shall be maintained within the following limits except as specified in 3.7.A.2 and 3.7.A.3.

   a. Minimum water volume - 84,000 ft^3

   b. Maximum water volume - 94,000 ft^3

   c. Maximum suppression pool bulk temperature during normal continuous power operation shall be $\leq 80^\circ F$, except as specified in 3.7.A.1.e.

   d. Maximum suppression pool bulk temperature during RCIC, HPCI or ADS operation shall be $\leq 90^\circ F$, except as specified in 3.7.A.1.e.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS

Applicability:

Applies to the primary and secondary containment integrity.

Objective:

To verify the integrity of the primary and secondary containment.

Specification:

A. Primary Containment

Suppression Pool

1. a. The suppression chamber water level and temperature shall be checked once per day.

   b. Whenever there is indication of relief valve operation or testing which adds heat to the suppression pool, the pool temperature shall be continually monitored and also observed and logged every 5 minutes until the heat addition is terminated.

   c. Whenever there is indication of relief valve operation with the bulk temperature of the suppression pool reaching $160^\circ F$ or more and the primary coolant system pressure greater than 200 psig, an external visual examination of the suppression chamber shall be conducted before resuming power operation.

LIMITING CONDITIONS FOR OPERATION

3.7. CONTAINMENT SYSTEMS (CONT)

A. Primary Containment (Cont)

e. In order to continue reactor power operation, the suppression chamber pool bulk temperature must be reduced to $\leq 80^\circ$F within 24 hours.

f. If the suppression pool bulk temperature exceeds the limits of Specification 3.7.A.1.d, RCIC, HPCI or ADS testing shall be terminated and suppression pool cooling shall be initiated.

g. If the suppression pool bulk temperature during reactor power operation exceeds 110°F, the reactor shall be scrammed.

h. During reactor isolation conditions, the reactor pressure vessel shall be depressurized to less than 200 psig at normal cool down rates if the pool bulk temperature reaches 120°F.

i. (Deleted)

j. (Deleted)

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

d. Whenever there is indication of relief valve operation with the local temperature of the suppression pool T-quencher reaching 200°F or more, an external visual examination of the suppression chamber shall be conducted before resuming power operation.

e. A visual inspection of the suppression chamber interior, including water line regions, shall be made at each major refueling outage.

f. (Deleted)

g. Suppression chamber water level shall be recorded at least once each shift when the differential pressure is required.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.7 CONTAINMENT SYSTEMS (CONT)	4.7 CONTAINMENT SYSTEMS (Cont)

3.7 CONTAINMENT SYSTEMS (CONT)

A. Primary Containment (Cont)

k. (Deleted)

l. (Deleted)

m. Suppression chamber water level shall be between -6 to -1 inches on torus level instrument which corresponds to a downcomer submergence of 3 feet to 3 feet 5 inches.

n. The suppression chamber can be drained if the conditions as specified in Section 3.5.F.5 of this Technical Specification are adhered to.

4.7 CONTAINMENT SYSTEMS (Cont)

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

Primary Containment Integrity

2. a. Primary containment integrity shall be maintained at all times when the reactor is critical or when the reactor water temperature is above 212°F and fuel is in the reactor vessel except while performing "open vessel" physics test at power levels not to exceed 5 Mw(t).

Primary containment integrity means that the drywell and pressure suppression chamber are intact and that all of the following conditions are satisfied:

1. All manual containment isolation valves on lines connected to the reactor coolant system or containment which are not required to be open during accident conditions are closed.
2. At least one door in each airlock is closed and sealed.
3. All blind flanges and manways are closed.
4. All automatic primary containment isolation valves and all instrument line flow check valves are operable except as specified in 3.7.A.2.b.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

Primary Containment Integrity

2. a. The primary containment integrity shall be demonstrated by performing Primary Containment Leak Tests in accordance with 10CFR50 Appendix J, Option B and Regulatory Guide 1.163 dated September 1995*, with exemptions as approved by the NRC and exceptions as follows:

1. The main steam line isolation valves shall be tested at a pressure $\geq$23 psig, and normalized to a value equivalent to P_a.
2. Personnel air lock door seals shall be tested at a pressure $\geq$10 psig. Results shall be normalized to a value equivalent to P_a.
3. Leakage rate acceptance criteria are:
   1. Primary containment overall leakage rate acceptance criterion is $\leq$1.0 L_a. During the first unit startup following testing in accordance with the Containment Leakage Rate Testing Program, the leakage rate acceptance criteria are $\leq$ 0.60 L_a for the Type B and Type C tests and $\leq$ 0.75 L_a for the Type A tests.
   2. Overall air lock leakage rate is $\leq$ 0.05 L_a when tested at $\geq P_a$.
   3. Door seals leakage rate is $\leq$ 0.01 L_a when pressurized to $\geq$ 10 psig.

* The definition of Surveillance Frequency is not applicable to Leak Rate Tests.

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

5. All containment isolation check valves are operable or at least one containment isolation valve in each line having an inoperable valve is secured in the isolated position.

Primary Containment Isolation Valves

2. b. In the event any automatic Primary Containment Isolation Valve becomes inoperable, at least one containment isolation valve in each line having an inoperable valve shall be deactivated in the isolated condition. (This requirement may be satisfied by deactivating the inoperable valve in the isolated condition. Deactivation means to electrically or pneumatically disarm, or otherwise secure the valve.)*

* Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative controls.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

4. Combined main steam lines: 46 scfh @ 23 psig.

where,

P_a = 45 psig
L_a = 1.0% by weight of the contained air @ 45 psig for 24 hrs.

4. NEI 94-01-1995. Section 9.2.3: The first Type A test performed after the May 25, 1995 Type A test shall be performed no later than May 25, 2010.

Primary Containment Isolation Valves

2. b. 1. The primary containment isolation valves surveillance shall be performed as follows:

   a. At least once per operating cycle the operable primary containment isolation valves that are power operated and automatically initiated shall be tested for simulated automatic initiation and closure times.

   b. Test primary containment isolation valves:

      1. Verify power operated primary containment isolation valve operability as specified in 3.13.

      2. Verify main steam isolation valve operability as specified in 3.13.

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont)

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

c. Deleted

d. Verify reactor coolant system instrument line flow check valve operability as specified in 3.13.

2. b. 2. Whenever a primary containment automatic isolation valve is inoperable, the position of the isolated valve in each line having an inoperable valve shall be recorded daily.

2.c. Continuous Leak Rate Monitor

When the primary containment is inerted, the containment shall be continuously monitored for gross leakage by review of the inerting system makeup requirements. This monitoring system may be taken out of service for maintenance but shall be returned to service as soon as practicable.

2.d. Drywell Surfaces

The interior surfaces of the drywell and torus above the water line shall be visually inspected every refueling outage for evidence of deterioration.

LIMITING CONDITION FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

3. Pressure Suppression Chamber - Reactor Building Vacuum Breakers

a. Except as specified in 3.7.A.3.b below, two pressure suppression chamber - reactor building vacuum breakers shall be operable at all times when primary containment integrity is required. The setpoint of the differential pressure instrumentation which actuates the pressure suppression chamber - reactor building breakers shall be 0.5 psig.

b. From and after the date that one of the pressure suppression chamber - reactor building vacuum breakers is made or found to be inoperable for any reason, reactor operation is permissible only during the succeeding seven days unless such vacuum breaker is sooner made operable, provided that the repair procedure does not violate primary containment integrity.

4. Drywell-Pressure Suppression Chamber Vacuum Breakers

a. When primary containment is required, all drywell-pressure suppression chamber vacuum breakers shall be operable except during testing and as stated in Specifications 3.7.A.4.b, c and d, below. Drywell-pressure suppression chamber vacuum breakers shall be considered operable if:

SURVEILLANCE REQUIREMENT

4.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

3. Pressure Suppression Chamber - Reactor Building Vacuum Breakers

a. Verify operability of the pressure suppression chamber-reactor building vacuum breakers as specified in 3.13.

b. Check the associated instrumentation including set points for proper operation every three months.

4. Drywell-Pressure Suppression Chamber Vacuum Breakers

a. Periodic Operability Tests

1. Once each month each drywell-pressure suppression chamber vacuum breaker shall be exercised and the operability of the valve and installed position indicators and alarms verified.

2. A drywell to suppression chamber differential pressure decay rate test shall be conducted at least every 3 months.

LIMITING CONDITION FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

1. The valve is demonstrated to open with the applied force of the installed test actuator as indicated by the position switches and remote position indicating lights.

2. The valve shall return by gravity when released after being opened by remote or manual means, to within 3/32" of the fully closed position.

3. Neither of the two position alarm systems, which annunciate in the Control Room when any vacuum breaker opening exceeds 3/32", are in alarm.

b. Any drywell-suppression chamber vacuum breaker may be non-fully closed as determined by the position switches provided that the drywell to suppression chamber differential decay rate is demonstrated to be not greater than 25% of the differential pressure decay rate for the maximum allowable bypass area of $0.2 ft^2$.

c. Reactor operation may continue provided that no more than 2 of the drywell-pressure suppression chamber vacuum breakers are determined to be inoperable provided that they are secured or known to be in the closed position.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

b. During each refueling interval:

1. Each vacuum breaker shall be tested to determine that the disc opens freely to the touch and returns to the closed position by gravity with no indication of binding.

2. Vacuum breaker position switches and installed alarm systems shall be calibrated and functionally tested.

3. At least 25% of the vacuum breakers shall be visually inspected such that all vacuum breakers shall have been inspected following every fourth refueling interval. If deficiencies are found, all vacuum breakers shall be visually inspected and deficiencies corrected.

4. A drywell to suppression chamber leak rate test shall demonstrate that the differential pressure decay rate does not exceed the rate which would occur through a 1 inch orifice without the addition of air or nitrogen.

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

d. If a failure of one of the two installed position alarm systems occurs for one or more vacuum breakers, reactor operation may continue provided that a differential pressure decay rate test is initiated immediately and performed every 15 days thereafter until the failure is corrected. The test shall meet the requirements of Specification 3.7.A.4.b.

5. If the specifications of 3.7.A.1 thru 3.7.A.4 cannot be met, an orderly shutdown shall be initiated and the reactor shall be in Cold Shutdown condition within 24 hours.

6. Oxygen Concentration

a. The primary containment atmosphere shall be reduced to less than 4% oxygen by volume with nitrogen gas while in RUN MODE during the time period:

i. From 24 hours after thermal power is greater than 15% rated thermal power following startup, to

ii. 24 hours prior to reducing thermal power to less than 15% rated thermal power prior to the next scheduled shutdown, except as specified in 3.7.A.6.b.

b. If the specifications of 3.7.A.6.a above cannot be met, and the primary containment oxygen concentration cannot be restored to less than 4% oxygen by volume within the subsequent 24 hour period, reactor thermal power shall be less than 15% rated thermal power within the next 8 hours.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

6. Oxygen Concentration

The primary containment oxygen concentration shall be measured and recorded at least twice weekly

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

7. Containment Atmosphere Dilution

a. Within the 24-hour period after placing the reactor in the Run Mode the Post - LOCA Containment Atmosphere Dilution System must be operable and capable of supplying nitrogen to the containment for atmosphere dilution. If this specification cannot be met, the system must be restored to an operable condition within 30 days or the reactor must be at least in Hot Shutdown within 12 hours.

b. Within the 24-hour period after placing the reactor in the Run Mode, the Nitrogen Storage Tank shall contain a minimum of 1500 gallons of liquid N_2. If this specification cannot be met the minimum volume will be restored within 30 days or the reactor must be in at least Hot Shutdown within 12 hours.

8. Drywell and Suppression Chamber Differential Pressure

a. Differential pressure between the drywell and suppression chamber shall be maintained at equal to or greater than 1.17 psid, while in RUN MODE during the time period:

i. From 24 hours after thermal power is greater than 15% rated thermal power following startup, to

ii. 24 hours prior to reducing thermal power to less than 15% rated thermal power prior to the next scheduled shutdown, except as specified in 3.7.A.8.b and c.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

7. Containment Atmosphere Dilution

a. The post-LOCA containment atmosphere dilution system shall be functionally tested once per operating cycle.

b. The level in the liquid N_2 storage tank shall be recorded weekly.

c. Not used.

d. Once per month each manual or power operated valve in the CAD system flow path not locked, sealed or otherwise secured in position shall be observed and recorded to be in its correct position.

8. Drywell and Suppression Chamber Differential Pressure

a. The pressure differential between the drywell and suppression chamber shall be recorded at least once each shift when the differential pressure is required.

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

b. The differential pressure may be reduced to less than 1.17 psid for a maximum of 4 hours for maintenance activities on the differential pressure control system and during required operability testing of the HPCI system, the relief valves, the RCIC system and the drywell-suppression chamber vacuum breakers.

c. If the specifications of 3.7.A.8.a and b above cannot be met, and the differential pressure cannot be restored within the subsequent 8 hour period, reactor thermal power shall be less than 15% rated thermal power within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont.)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System

1. Standby Gas Treatment System

a. Except as specified in 3.7.B.1.c or 3.7.B.1.e below, both trains of the standby gas treatment shall be operable when in the Run, Startup, and Hot Shutdown MODES, during movement of recently irradiated fuel assemblies in the secondary containment, and during operations with a potential for draining the reactor vessel (OPDRVs),

or

the reactor shall be in cold shutdown within the next 36 hours.

b. 1. The results of the in-place cold DOP tests on HEPA filters shall show $\geq$99% DOP removal. The results of halogenated hydrocarbon tests on charcoal adsorber banks shall show $\geq$99.9% halogenated hydrocarbon removal.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont.)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System

1. Standby Gas Treatment System

a. 1. At least once per operating cycle, it shall be demonstrated that pressure drop across the combined high efficiency filters and charcoal adsorber banks is less than 8 inches of water at 4000 cfm.

2. At least once per operating cycle, demonstrate that the inlet heaters on each train are operable and are capable of an output of at least 20 kW.

3. The tests and analysis of Specification 3.7.B.1.b. shall be performed at least once per operating cycle or following painting, fire or chemical release in any ventilation zone communicating with the system while the system is operating that could contaminate the HEPA filters or charcoal adsorbers.

4. At least once per operating cycle, automatic initiation of

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont.)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System (Cont.)

b. 2. The results of the laboratory carbon sample analysis shall show each carbon adsorber bank is capable of $\geq$97.5% methyl iodide removal at 70% R.H. and 86°F. The carbon sample shall be obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978 and tested in accordance with ASTM D3803-1989. The analysis results are to be verified as acceptable within 31 days after sample removal, or declare that train inoperable and take the actions specified in 3.7.B.1.c.

c. From and after the date that one train of the Standby Gas Treatment System is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding seven days providing that within 2 hours all active components of the other standby gas treatment train are verified to be operable and the diesel generator associated with the operable train is operable.

If the system is not made fully operable within 7 days, reactor shutdown shall be initiated and the reactor shall be in cold shutdown within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont.)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System (Cont.)

each branch of the standby gas treatment system shall be demonstrated, with Specification 3.7.B.1.d satisfied.

5. Each train of the standby gas treatment system shall be operated for at least 15 minutes per month.

6. The tests and analysis of Specification 3.7.B.1.b.2 shall be performed after every 720 hours of system operation.

b. 1. In-place cold DOP testing shall be performed on the HEPA filters after each completed or partial replacement of the HEPA filter bank and after any structural maintenance on the HEPA filter system housing which could affect the HEPA filter bank bypass leakage.

2. Halogenated hydrocarbon testing shall be performed on the charcoal adsorber bank after each partial or complete replacement of the charcoal adsorber bank or after any structural maintenance on the charcoal adsorber housing which could affect the charcoal adsorber bank bypass leakage.

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (CONT)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System (Cont)

d. Fans shall operate within ± 10% of 4000 cfm.

e. From and after the date that one train of the Standby Gas Treatment System is made or found to be inoperable for any reason, movement of recently irradiated fuel assemblies and operations with a potential for draining the reactor vessel (OPDRVs) are permissible only during the succeeding 7 days providing that within 2 hours all active components of the other train are verified to be operable and the diesel generator associated with the operable train is operable.

If the system is not made fully operable within 7 days,

i) place the operable train in operation immediately

OR

ii) suspend movement of recently irradiated fuel assemblies in secondary containment and initiate actions to suspend OPDRVs. Any fuel assembly movement in progress may be completed.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System (Cont)

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont.)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System (Cont.)

2. Control Room High Efficiency Air Filtration System (CRHEAFS)

------------------NOTE--------------------------
The main control room envelope (CRE) boundary may be opened intermittently under administrative control.
----

a. Except as specified in Specification 3.7.B.2.c, 3.7.B.2.e, 3.7.B.2.f, or 3.7.B.2.g below, both trains of the Control Room High Efficiency Air Filtration System used for the processing of inlet air to the control room under accident conditions shall be OPERABLE when in the Run, Startup, and Hot Shutdown MODES, during movement of recently irradiated fuel assemblies in the secondary containment, and during operations with a potential for draining the reactor vessel (OPDRVs), otherwise, the reactor shall be in cold shutdown within the next 36 hours.

b. 1. The results of the in-place cold DOP tests on HEPA filters shall show ≥99% DOP removal. The results of the halogenated hydrocarbon tests on charcoal adsorber banks shall show ≥99.9% halogenated hydrocarbon removal when test results are extrapolated to the initiation of the test.

2. The results of the laboratory carbon sample analysis shall show ≥97.5% methyl iodide removal at 70% R.H. and 86°F. The carbon sample shall be obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978 and tested in accordance with ASTM D3803-1989. The analysis results

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont.)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System (Cont.)

2. Control Room High Efficiency Air Filtration System (CRHEAFS)

a. At least once per operating cycle the pressure drop across each combined filter train shall be demonstrated to be less than 6 inches of water at 1000 cfm or the calculated equivalent.

b. 1. The tests and analysis of Specifications 3.7.B.2.b shall be performed once per operating cycle or following painting, fire or chemical release in any ventilation zone communicating with the system while the system is operating.

2. In-place cold DOP testing shall be performed after each complete or partial replacement of the HEPA filter bank or after any structural maintenance on the system housing which could affect the HEPA filter bank bypass leakage.

3. Halogenated hydrocarbon testing shall be performed after each complete or partial replacement of the charcoal adsorber bank or after any structural maintenance on the system housing which could affect the charcoal adsorber bank bypass leakage.

4. Each train shall be operated with the heaters in automatic for at least 15 minutes every month.

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont.)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System (CRHEAFS) (Cont)

are to be verified as acceptable within 31 days after sample removal, or declare that train inoperable and take the actions specified in 3.7.B.2.c.

c. From and after the date that one train of the CRHEAFS is made or found to be inoperable for any reason other than 3.7.B.2.f, reactor operation is permissible only during the succeeding 7 days providing that within 2 hours all active components of the other CRHEAFS train are verified to be OPERABLE and the diesel generator associated with the OPERABLE train is OPERABLE. If the system is not made fully OPERABLE within 7 days, reactor shutdown shall be initiated and the reactor shall be in cold shutdown within the next 36 hours.

d. Fans shall operate within ± 10% of 1000 cfm.

e. From and after the date that one train of the CRHEAFS is made or found to be inoperable for any reason other than 3.7.B.2.g, movement of recently irradiated fuel assemblies and operations with a potential for draining the reactor vessel (OPDRVs) are permissible during the succeeding 7 days providing that within 2 hours all active components of the other train are verified to be OPERABLE and the diesel generator associated with the OPERABLE train is OPERABLE. If the system is not made fully OPERABLE within 7 days,

i) perform surveillance 4.7.B.2.b.4 for the OPERABLE CRHEAF train every 24 hours

OR

ii) immediately suspend movement of recently irradiated fuel assemblies

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont.)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System (CRHEAFS) (Cont)

5. The test and analysis of Specification 3.7.B.2.b.2 shall be performed after every 720 hours of system operation.

c. At least once per operating cycle demonstrate that the inlet heaters on each train are OPERABLE and capable of an output of at least 14 kw.

d. Perform an instrument functional test on the humidistats controlling the heaters once per operating cycle

e. Perform required CRE unfiltered air inleakage testing at the specified frequency, in accordance with the Control Room Habitability Program.

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont.)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System (CRHEAFS) (Cont)

in secondary containment and initiate actions to suspend OPDRVs. Any fuel assembly movement in progress may be completed.

f. Upon discovery that one or more trains of CRHEAFS are inoperable due to an inoperable CRE boundary when in the Run, Startup and Hot Shutdown MODES:

i.) Immediately initiate actions to mitigate the cause of the inoperable CRE boundary.

AND

ii.) Within 24 hours, verify the effectiveness of the mitigating actions to ensure CRE occupant exposures to radiological, chemical, and smoked hazards will not exceed limits.

AND

iii.) Within 90 days restore the CRE boundary to OPERABLE status.

Otherwise be in Hot Shutdown within 12 hours and in Cold Shutdown within the following 24 hours.

g. Upon discovery that:

both trains of CRHEAFS are inoperable,

OR

one or more trains of CRHEAFS are inoperable due to an inoperable CRE boundary

during movement of recently irradiated fuel assemblies and operations with a potential for draining the reactor vessel (OPDRVs), immediately suspend movement of recently irradiated fuel assemblies in secondary containment and initiate actions to suspend OPDRVs. Any fuel assembly movement in progress may be completed.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont.)

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System (CRHEAFS) (Cont)

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont.)

C. Secondary Containment

1. Secondary containment shall be OPERABLE when in the Run, Startup and Hot Shutdown MODES, during movement of recently irradiated fuel assemblies in the secondary containment, and during operations with a potential for draining the reactor vessel (OPDRVs).

2. a. With Secondary Containment inoperable when in the Run, Startup and Hot Shutdown MODES, restore Secondary Containment to OPERABLE status within 4 hours.

   b. Required Action and Completion Time of 2.a not met, be in HOT Shutdown in 12 hours AND Cold Shutdown within 36 hours.

   c. With Secondary Containment inoperable during movement of recently irradiated fuel assemblies in the secondary containment and during OPDRVs, immediately:

      1. Suspend movement of recently irradiated fuel assemblies in the secondary containment.

         AND

      2. Initiate actions to suspend OPDRVs.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont.)

C. Secondary Containment

1. Each refueling outage prior to refueling, secondary containment capability shall be demonstrated to maintain 1/4 inch of water vacuum under calm wind (5 mph) conditions with a filter train flow rate of not more than 4000 cfm.

LIMITING CONDITIONS FOR OPERATION

3.8 PLANT SYSTEMS

1. Main Condenser Offgas

LCO 3.8.1

The gross gamma activity rate of noble gases measured at a main condenser pretreatment monitor station shall be limited to 500,000 μ Ci/second.

APPLICABILITY:

At all times when steam is available to the air ejectors.

ACTIONS:

A. With the gross gamma activity rate of the noble gases not within limits;

1. Restore the gross gamma activity rate of the noble gases to within the limit within 72 hours.

B. Required Action and associated Completion Time not met.

1. Isolate SJAE within 12 hours.

OR

2.1 Be in HOT SHUTDOWN within 12 hours.

AND

2.2 Be in COLD SHUTDOWN within 36 hours.

SURVEILLANCE REQUIREMENTS

4.8 PLANT SYSTEMS

1. Main Condenser Offgas

1. ---------------NOTE---------------
Not Required to be performed until 31 days after any SJAE in operation.

Verify the gross gamma activity rate of the noble gases is ≤ 500,000 μ Ci/second:

a. At least once per 31 days.

AND

b. Once within 4 hours after a ≥ 50% increase in the nominal steady state fission gas release after factoring out increase due to changes in THERMAL POWER level or hydrogen injection.

LIMITING CONDITIONS FOR OPERATION

3.8 PLANT SYSTEMS (CONT)

2. Mechanical Vacuum Pump Isolation Instrumentation

LCO 3.8.2

Four channels of the Main Steam Line Radiation Monitoring System Radiation - High function for the mechanical vacuum pump shall be OPERABLE

APPLICABILITY:

Whenever any main steam isolation valve is open with steam flowing.

ACTIONS:

-----------------NOTE----------------------
Separate Condition Entry is allowed for each channel.

A. One or more required channels inoperable.

   1. Restore channel to OPERABLE status within 24 hours.

   OR

   2. --------------NOTE----------------
   Not Applicable if inoperable channel is the result of an inoperable isolation valve.

   Place channel or associated trip system in trip within 24 hours.

B. Required Action and associated Completion Time of Condition A not met.

   OR

   Mechanical vacuum pump isolation capability not maintained.

   1. Isolate mechanical vacuum within 12 hours.

   OR

   2. Isolate Main Steam Lines within 12 hours.

   OR

   3. Be in HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.8 PLANT SYSTEMS (CONT)

2. Mechanical Vacuum Pump Isolation Instrumentation

-----------------NOTE-------------------
When a channel is placed in an inoperable status solely for the performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains mechanical vacuum pump isolation capacity.
----

1. Perform a CHANNEL CHECK every 12 hours.

2. Calibrate the trip units every 92 days.

3. Perform a CHANNEL CALIBRATION every 24 months. The allowable trip value shall be ≤ 5.5 x normal background.

4. Perform a LOGIC SYSTEM FUNCTIONAL TEST including isolation valve actuation every 24 months.

LIMITING CONDITIONS FOR OPERATION

3.9 AUXILIARY ELECTRICAL SYSTEM

Applicability:

Applies to the auxiliary electrical power system.

Objective:

To assure an adequate supply of electrical power for operation of those systems required for safety.

Specification:

A. Auxiliary Electrical Equipment

The reactor shall not be made critical unless all of the following conditions are satisfied:

1. At least one off-site transmission line and the startup transformer are available and capable of automatically supplying auxiliary power to the emergency buses.
2. An additional source of off-site power consisting of one of the following:
   a. A transmission line and shutdown transformer capable of supplying power to the emergency 4160 volt buses.
   b. The main transformer and unit auxiliary transformer available and capable of supplying power to the emergency 4160 volt buses.
3. Both diesel generators shall be operable. Each diesel generator shall have a minimum of 36,800 gallons of diesel fuel on site. Of this volume, at least 19,800 gallons of fuel shall be stored in each EDG Class I fuel system. The balance of the 36,800 gallons/EDG shall be available in the Station Blackout diesel generator tanks.

SURVEILLANCE REQUIREMENTS

4.9 AUXILIARY ELECTRICAL SYSTEM

Applicability:

Applies to the periodic testing requirements of the auxiliary electrical systems.

Objective:

Verify the operability of the auxiliary electrical system.

Specification:

A. Auxiliary Electrical Equipment Surveillance

1. Diesel Generators
   a. Each diesel generator shall be manually started and loaded once each month to demonstrate operational readiness. The test shall continue for at least a one hour period at rated load.

      During the monthly generator test the diesel generator starting air compressor shall be checked for operation and its ability to recharge air receivers. The operation of the diesel fuel oil transfer pumps shall be demonstrated, and the diesel starting time to reach rated voltage and frequency shall be logged.
   b. Once per operating cycle the condition under which the diesel generator is required will be simulated and test conducted to demonstrate that it will start and accept the emergency load within the specified time sequence. The results shall be logged.

LIMITING CONDITIONS FOR OPERATION

3.9 AUXILIARY ELECTRICAL SYSTEM

A. Auxiliary Electrical Equipment (Cont)

SURVEILLANCE REQUIREMENTS

4.9 AUXILIARY ELECTRICAL SYSTEM

A. Auxiliary Electrical Equipment Surveillance (Cont)

1. Verifying de-energization of the emergency buses and load shedding from the emergency buses.

2. Verifying the diesel starts from ambient condition on the auto-start signal, energizes the emergency buses with permanently connected loads, energizes the auto-connected emergency loads through the load sequence, and operates for ≥ 5 minutes while its generator is loaded with the emergency loads.

   During performance of this surveillance verify that HPCI and RCIC inverters do not trip.

   The results shall be logged.

c. Once per operating cycle with the diesel loaded per 4.9.A.1.b verify that on diesel generator trip, secondary (offsite) AC power is automatically connected within 11.8 to 13.2 seconds to the emergency service buses and emergency loads are energized through the load sequencer in the same manner as described in 4.9.A.1.b.2.

   The results shall be logged.

LIMITING CONDITIONS FOR OPERATION

3.9 AUXILIARY ELECTRICAL SYSTEM

A. Auxiliary Electrical Equipment (Cont)

4. 4160 volt buses A5 and A6 are energized and the associated 480 volt buses are energized.

5. The station and switchyard 125 and 250 volt batteries are operable. Each battery shall have an operable battery charger.

6. Emergency Bus Degraded Voltage Annunciation System as specified in Table 3.2.B.1 is operable.

7. Specification:

Two redundant RPS Electrical Protection Assemblies (EPAs) shall be operable at all times on both inservice power supplies.

Action

a. With one EPA on an inservice power supply inoperable, continued operation is permissible provided that the EPA is returned to operable status or power is transferred to a source with two operable EPAs within 72 hours. If this requirement cannot be met, trip the power source.

b. With both RPS EPAs found to be inoperable on an inservice power supply, continued operation is permissible, provided at least one EPA is restored to operable status or power is transferred to a source with at least one operable EPA within 30 minutes. If this requirement cannot be met, trip the power source.

NOTE: Only applicable if tripping the power source would not result in a scram.

SURVEILLANCE REQUIREMENTS

4.9 AUXILIARY ELECTRICAL SYSTEM

A. Auxiliary Electrical Equipment Surveillance (Cont)

d. Once a month the quantity of diesel fuel available on-site shall be logged.

e. Once a month a sample of diesel fuel shall be checked for quality in accordance with ASTM D4057-81 or D4177-82. The quality shall be within the acceptable limits specified in Table 1 of ASTM D975-81 and logged.

2. Station and Switchyard Batteries

a. Every week the specific gravity, the voltage and temperature of the pilot cell and overall battery voltage shall be measured and logged.

b. Every three months the measurements shall be made of voltage of each cell to nearest 0.1 volt, specific gravity of each cell, and temperature of every fifth cell. These measurements shall be logged.

c. Once each operating cycle, the stated batteries shall be subjected to a Service Discharge Test (load profile). The specific gravity and voltage of each cell shall be determined after the discharge and logged.

d. Once every five years, the stated batteries shall be subjected to a Performance Discharge Test (capacity). This test will be performed in lieu of the Service Discharge Test requirements of 4.9.A.2.C above.

LIMITING CONDITIONS FOR OPERATION

3.9 AUXILIARY ELECTRICAL SYSTEM (Cont)

B. Operation with Inoperable Equipment

Whenever the reactor is in Run Mode or Startup Mode with the reactor not in a Cold Condition, the availability of electric power shall be as specified in 3.9.B.1, 3.9.B.2, 3.9.B.3, 3.9.B.4, and 3.9.B.5.

1. From and after the date that incoming power is not available from the startup or shutdown transformer, continued reactor operation is permissible under this condition for:

   a. 3 days with the startup transformer inoperable

   or

   b. 7 days with the shutdown transformer inoperable

   During this period, both diesel generators and associated emergency buses must remain operable.

2. From and after the date that incoming power is not available from both startup and shutdown transformers, continued operation is permissible, provided both diesel generators and associated emergency buses remain operable, all core and containment cooling systems are operable, and reactor power level is reduced to 25% of design.

3. From and after the date that one of the diesel generators or associated emergency bus is made or found to be inoperable for any reason, continued reactor operation is permissible in accordance with Specifications 3.4.B.1, 3.5.F.1, 3.7.B.1.c, 3.7.B.1.e, 3.7.B.2.c, and 3.7.B.2.e if Specification 3.9.A.1 and 3.9.A.2.a are satisfied.

SURVEILLANCE REQUIREMENTS

4.9 AUXILIARY ELECTRICAL SYSTEM (Cont)

Auxiliary Electrical Equipment Surveillance (Cont)

3. Emergency 4160V Buses A5-A6 Degraded Voltage Annunciation System.

   a. Once each operating cycle, calibrate the alarm sensor.

   b. Once each 31 days perform a channel functional test on the alarm system.

   c. In the event the alarm system is determined inoperable under 3.b above, commence logging safety related bus voltage every 30 minutes until such time as the alarm is restored to operable status.

4. RPS Electrical Protection Assemblies

   a. Each pair of redundant RPS EPAs shall be determined to be operable at least once per 6 months by performance of an instrument functional test.

   b. Once per 18 months each pair of redundant RPS EPAs shall be determined to be operable by performance of an instrument calibration and by verifying tripping of the circuit breakers upon the simulated conditions for automatic actuation of the protective relays within the following limits:

Overvoltage	$\leq$ 132 volts
Undervoltage	$\geq$ 108 volts
Underfrequency	$\geq$ 57Hz

B. Operation with Inoperable Equipment (Cont)

4. From and after the date that one of the diesel generators or associated emergency buses and either the shutdown or startup transformer power source are made or found to be inoperable for any reason, continued reactor operation is permissible for 48 hours provided:

   a. The startup transformer and both offsite 345kV transmission lines are available and capable of automatically supplying auxiliary power to the emergency 4160 volt buses,

   OR

   b. The 23kV transmission line and associated shutdown transformer are available and capable of automatically supplying auxiliary power to the emergency 4160 volt buses

5. From and after the date that one of the 125 or 250 volt battery systems is made or found to be inoperable for any reason, continued reactor operation is permissible during the succeeding three days within electrical safety considerations, provided repair work is initiated in the most expeditious manner to return the failed component to an operable state, and Specification 3.5.F is satisfied.

6. With the emergency bus voltage less than 3958.5V but above 3878.7V (excluding transients) during normal operation, transfer the safety related buses to the diesel generators. If grid voltage continues to degrade be in at least Hot Shutdown within the next 4 hours and in Cold Shutdown within the following 12 hours unless the grid conditions improve.

LIMITING CONDITION FOR OPERATION

3.10 CORE ALTERATIONS

Applicability:

Applies to the fuel handling and core reactivity limitations during refueling and core alterations.

Objective:

To ensure that core reactivity is within the capability of the control rods and to prevent criticality during refueling.

Specification:

A. Refueling Interlocks

1. During in-vessel fuel movement with equipment associated with the interlocks the refueling equipment interlocks shall be operable with the reactor mode switch locked in the "Refuel" position. If one or more required refueling equipment interlocks are inoperable:

   a. Suspend in-vessel fuel movement with equipment associated with the inoperable interlock(s) immediately.

   OR

   b. Insert a control rod withdrawal block AND verify all control rods are fully inserted.

2. When the reactor vessel head is removed and any control rod is withdrawn the one-rod-out interlock shall be operable with the reactor mode switch locked in the "Refuel" position. If the one-rod-out interlock is inoperable:

   a. Suspend control rod withdrawal immediately.

   AND

   b. Initiate action to fully insert all control rods in core cells containing one or more fuel assemblies immediately.

SURVEILLANCE REQUIREMENTS

4.10 CORE ALTERATIONS

Applicability:

Applies to the period testing of those interlocks and instrumentation used during refueling and core alterations.

Objective:

To verify the operability of instrumentation and interlocks used in refueling and core alterations.

Specification:

A. Refueling Interlocks

1. Prior to in-vessel fuel movement with equipment associated with the refueling equipment interlocks, the interlocks shall be functionally tested. They shall be tested at weekly intervals thereafter until no longer required.

2. When the reactor vessel head is removed and any control rod is withdrawn the one-rod-out interlock shall be functionally tested at weekly intervals. The functional test is not required to be performed until 1 hour following withdrawing a control rod.

LIMITING CONDITION FOR OPERATION

3.10 CORE ALTERATIONS (Cont)

B. Core Monitoring

During core alterations when fuel is in the vessel two SRM's shall be operable, one in the core quadrant where fuel or control rods are being moved and one in an adjacent quadrant. For an SRM to be considered operable, the following conditions shall be satisfied:

1. The SRM shall be inserted to the normal operating level. (Use of special moveable, dunking type detectors during initial fuel loading and major core alterations in place of normal detectors is permissible as long as the detector is connected to the normal SRM circuit.)

SURVEILLANCE REQUIREMENTS

4.10 CORE ALTERATIONS (Cont)

B. Core Monitoring

Prior to making any alterations to the core the SRM's shall be functionally tested and checked for neutron response. Thereafter, while required to be operable, the SRM's will be checked daily for response.

LIMITING CONDITION FOR OPERATION

3.10 CORE ALTERATIONS (Cont)

B. Core Monitoring (Cont)

2. The SRM shall have a minimum of 3 cps except as specified in 3 and 4 below.

3. Prior to spiral unloading, the SRM's shall have an initial count rate of ≥ 3 cps. During spiral unloading, the count rate on the SRM's may drop below 3 cps.

4. During spiral reload, each control cell shall have at least one assembly with a minimum exposure of 1000 MWD/ST.

C. Spent Fuel Pool Water Level

Whenever irradiated fuel is stored in the spent fuel pool, the pool water level shall be maintained at or above 33 feet.

SURVEILLANCE REQUIREMENTS

4.10 CORE ALTERATIONS (Cont)

B. Core Monitoring (Cont)

Spiral Reload

During spiral reload, SRM operability will be verified by using a portable external source every 12 hours until the required amount of fuel is loaded to maintain 3 cps. As an alternative to the above, up to two fuel assemblies will be loaded in different cells containing control blades around each SRM to obtain the required 3 cps. Until these assemblies have loaded, the cps requirement is not necessary.

C. Spent Fuel Pool Water Level

Whenever irradiated fuel is stored in the spent fuel pool, the water level shall be recorded daily.

LIMITING CONDITIONS FOR OPERATION

3.11 REACTOR FUEL ASSEMBLY

Applicability:

The Limiting Conditions for Operation associated with fuel rods apply to those parameters which monitor the fuel rod operating conditions.

Objective:

The Objective of Limiting Conditions for Operation is to assure the performance of the fuel rods.

Specifications:

A. Average Planar Linear Heat Generation Rate (APLHGR)

During operation at ≥ 25% rated thermal power, the APLHGR for each type of fuel as a function of average planar exposure shall not exceed the applicable limiting value specified in the CORE OPERATING LIMITS REPORT.

If at any time during operation at ≥ 25% rated thermal power the limiting value for APLHGR is being exceeded, action shall be initiated within 15 minutes to restore operation to within the prescribed limits. If the APLHGR is not returned to within the prescribed limits within two (2) hours, reduce thermal power to < 25% within four (4) hours.

SURVEILLANCE REQUIREMENTS

4.11 REACTOR FUEL ASSEMBLY

Applicability:

The surveillance requirements apply to the parameters which monitor the fuel rod operating conditions.

Objective:

The Objective of the Surveillance Requirements is to specify the type and frequency of surveillance to be applied to the fuel rods.

Specifications:

A. Average Planar Linear Heat Generation Rate (APLHGR)

The APLHGR for each type of fuel as a function of average planar exposure shall be determined daily during reactor operation at ≥ 25% rated thermal power.

LIMITING CONDITIONS FOR OPERATION

3.11 REACTOR FUEL ASSEMBLY (Cont)

B. Linear Heat Generation Rate (LHGR)

During operation at ≥ 25% rated thermal power, the LHGR shall not exceed the limits specified in the CORE OPERATING LIMITS REPORT.

If at any time during operation at ≥ 25% rated thermal power, the limiting value for LHGR is being exceeded, action shall be initiated within 15 minutes to restore operation to within the prescribed limits. If the LHGR is not returned to within the prescribed limits within two (2) hours, reduce thermal power to < 25% within four (4) hours.

C. Minimum Critical Power Ratio (MCPR)

1. During operation at ≥ 25% rated thermal power, MCPR shall be ≥ the MCPR operating limit specified in the Core Operating Limits Report. If at any time during operation at ≥ 25% rated thermal power, the limiting value for MCPR is being exceeded, action shall be initiated within 15 minutes to restore operation to within the prescribed limits. If the steady state MCPR is not returned to within the prescribed limits within two (2) hours, reduce thermal power to < 25% within four (4) hours.

SURVEILLANCE REQUIREMENTS

4.11 REACTOR FUEL ASSEMBLY (Cont)

B. Linear Heat Generation Rate (LHGR)

The LHGR as a function of core height shall be checked daily during reactor operation at ≥ 25% rated thermal power.

C. Minimum Critical Power Ratio (MCPR)

1. MCPR shall be determined daily during reactor power operation at ≥ 25% rated thermal power and following any change in power level or distribution that would cause operation with a limiting control rod pattern as specified in Table 3.2.C.1 Note 5.

2. The value of τ in Specification 3.11.C.2. shall be equal to 1.0 unless determined from the result of surveillance testing of Specification 4.3.C as follows:

   a) τ is defined as

$$\tau = \frac{\tau_{ave} - \tau_B}{1.252 - \tau_B}$$

LIMITING CONDITIONS FOR OPERATION

3.11 REACTOR FUEL ASSEMBLY (Cont)

C. Minimum Critical Power Ratio (MCPR) (Cont'd)

2. The operating limit MCPR values as a function of the τ are given in Table 3.3-1 of the Core Operating Limits Report where τ is given by specification 4.11.C.2.

SURVEILLANCE REQUIREMENTS

4.11 REACTOR FUEL ASSEMBLY (Cont)

C. Minimum Critical Power Ratio (MCPR) (Cont'd)

b. The average scram time to dropout of Notch 34 is determined as follows:

$$\tau_{ave} = \frac{\sum_{i=1}^{n} N_i \tau_i}{\sum_{i=1}^{n} N_i}$$

Where: an n = number of surveillance tests performed to date in the cycle.

N_i = number of active control rods measured in the i^{th} surveillance test.

τ_i = average scram time to dropout of Notch 34 of all rods measured in the i^{th} surveillance test.

c. The adjusted analysis mean scram time (τ_B) is calculated as follows:

$$\tau_B = \mu + 1.65 \left[\frac{N_1}{\sum_{i=1}^{n} N_i} \right]^{1/2} \sigma$$

Where:

μ = mean of the distribution for average scram insertion time to dropout of Notch 34, 0.937 sec.

N_1 = total number of active control rods at BOC during the first surveillance test.

σ = standard deviation of the distribution for average scram insertion time to the dropout of Notch 34, 0.021 seconds.

LIMITING CONDITIONS FOR OPERATION

3.11 REACTOR FUEL ASSEMBLY (Cont)

D. Power/Flow Relationship During Power Operation

The power/flow relationship shall not exceed the limiting values specified in the CORE OPERATING LIMITS REPORT.

If at any time during power operation it is determined by normal surveillance that the limiting value for the power/flow relationship is being exceeded, action shall be initiated within 15 minutes to restore operation to within the prescribed limits. If the power/flow relationship is not returned to within the prescribed limits within two (2) hours, the reactor shall be brought to the Cold Shutdown condition within 36 hours. Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.

SURVEILLANCE REQUIREMENTS

4.11 REACTOR FUEL ASSEMBLY (Cont)

D. Power/Flow Relationship During Power Operation

Compliance with the power/flow relationship in Section 3.11.D shall be determined daily during reactor operation.

3.12 FIRE PROTECTION

Alternate Shutdown Panels

1. Alternate shutdown panels for the following systems shall be OPERABLE:

    1. Core Spray
    2. RHR
    3. RBCCW
    4. Salt Service Water
    5. HPCI
    6. RCIC
    7. Automatic Depressurization
    8. Diesel Generators

APPLICABILITY:

At all times that the system is required to be OPERABLE.

ACTION:

With any of the alternate shutdown panels inoperable,

a. Immediately verify that fire detection with automatic fire suppression for the Cable Spreading Room is Operable. If fire detection with automatic fire suppression cannot be determined operable, within one (1) hour from the time the system is determined to be inoperable, establish a continuous Fire Watch with backup fire suppression.

b. Immediately verify that fire detector zones listed on Table 3.12 are operable for the respective system fire zone(s) for which the panel(s) provided alternate shutdown capability.

   If fire detection zone cannot be determined operable, establish an hourly fire watch patrol to inspect the affected zone(s).

4.12 FIRE PROTECTION

Alternate Shutdown Panels

The alternate shutdown panels shall be demonstrated to be OPERABLE according to the following:

1. The motor operated valves of the core spray system shall be operated from the alternate shutdown panels once each cycle.

2. The motor operated valves of the RHR system shall be operated once each cycle utilizing the MCC B-17 alternate power source.

3. The pumps of the SSW system shall be operated from the alternate shutdown panels once each cycle.

4. The pumps and motor operated valves of the RBCCW system shall be operated from the alternate shutdown panels once each cycle.

5. Alternate shutdown panel capability for the RCIC and HPCI systems shall be verified to be OPERABLE once each cycle.

6. After each refueling outage and prior to startup, perform a test from the alternate shutdown panel to verify that the relief valve solenoids of the Automatic Depressurization System (ADS) actuate.

7. Once each refueling outage, the diesel generator control circuits shall be isolated from the Cable Spreading Room and the diesel generator started.

PNPS

TABLE 3.12

FIRE DETECTOR
ZONES ASSOCIATED WITH
ALTERNATE SHUTDOWN PANELS

Alternate Shutdown System	Fire Zone	Detection Panel/Det. Zones
Core Spray	1.1 & .2	C-224/4A
RHR	1.1 & .2	C223/3C
RBCCW	1.21 & .22	C-222/2A & 2B
SSW	5.1 & .2 & .3	N/A
HPCI	1.3 & .4	C-223/3D & 3E
RCIC	1.5	C-223/3A & 3B
ADS	1.1 & .2	C-224/4A
DGS	4.1 & .3	C-93/1 & 2

LIMITING CONDITIONS FOR OPERATION

3.13 INSERVICE CODE TESTING

Applicability:

Applies to ASME Code Class 1, 2 and 3 or pumps and valves.

Objective:

To assure the operational readiness of ASME Code Class 1, 2, and 3 pumps and valves.

Specification:

A. Inservice Code Testing of Pumps and Valves

1. Based on the Facility Commercial Operation Date, Inservice Code Testing of ASME Code Class 1, 2 and 3 pumps and valves shall be performed in accordance with the Inservice Code Testing Program.

SURVEILLANCE REQUIREMENTS

4.13 INSERVICE CODE TESTING

Applicability:

Applies to the periodic testing requirements of ASME Code Class 1, 2 and 3 pumps and valves.

Objective:

To assess the operational readiness of ASME Code Class 1, 2, and 3 pumps and valves by performance of inservice tests.

Specification:

A. Inservice Code Testing of Pump and Valves

1. The ASME OM Code terminology for Inservice Test activities is as follows.

Code Terminology	Frequencies
Weekly	7 Days
Monthly	31 Days
Quarterly or 3 Mths	92 Days
Semiannually/ 6 Mths	184 Days
9 Months	276 Days
Yearly/Annually	366 Days
Biannual/2 Yrs	732 Days

2. The provisions in Definitions (1.0) for REFUELING INTERVAL, SURVEILLANCE FREQUENCY, and SURVEILLANCE INTERVAL are applicable to Code testing and to the above frequencies for performing Code testing activities.

3. Performance of Code testing shall be in addition to other specified Surveillance Requirements.

4. Nothing in the Inservice Code Testing Program shall supersede the requirements of Technical Specifications.

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LIMITING CONDITIONS FOR OPERATION

3.14 SPECIAL OPERATIONS

A. Inservice Hydrostatic and Leak Testing Operation

Specification

The average reactor coolant temperature specified in the definition of "Cold Shutdown" and "Cold Condition" may be considered "NA", and operation considered not to be >212° F or in "Hot Shutdown" to allow reactor coolant temperature >212° F:

- For performance of an inservice hydrostatic test or leak test,
- As a consequence of maintaining adequate pressure for an inservice hydrostatic test or leak test, or
- As a consequence of maintaining adequate pressure for control rod scram time testing initiated in conjunction with an inservice hydrostatic test or leak test.

Provided the following requirements are met:

Table 3.2A	Reactor Low Water Instrumentation
LCO 3.7.B.1	Standby Gas Treatment System (SGTS)
LCO 3.7.C.1	Secondary Containment

Applicability

During performance of inservice hydrostatic testing and system leakage pressure tests of the reactor coolant system with average coolant temperature >212° F.

SURVEILLANCE REQUIREMENTS

4.14 SPECIAL OPERATIONS

A. Inservice Hydrostatic and Leak Testing Operation

Perform the applicable surveillance requirements for the required LCOs at the frequency specified by the applicable surveillance requirements.

Actions

NOTE: Separate Condition entry is allowed for each requirement of the LCO.

A. One or more of the above requirements not met:

1. **NOTE:** Required Actions to be in Cold Shutdown/Cold Condition include reducing average reactor coolant temperature to $\leq$ 212° F.

   Immediately enter the applicable Condition of the affected LCO.

   OR

2.1 Immediately suspend activities that could increase the average reactor coolant temperature or pressure.

   AND

2.2 Reduce average reactor coolant temperature to $\leq$ 212° F within 24 hours.

LIMITING CONDITIONS FOR OPERATION

3.14 SPECIAL OPERATIONS (continued)

B. (Not Used)

SURVEILLANCE REQUIREMENTS

4.14 SPECIAL OPERATIONS (continued)

B. (Not Used)

LIMITING CONDITIONS FOR OPERATION

3.14 SPECIAL OPERATIONS (continued)

C. Single Control Rod Withdrawal – Hot Shutdown

Specification

The MODE definition specified in Specification 1.0 for Hot Shutdown may be changed to include the reactor mode switch in the Refuel position, and operation considered not to be in Refuel MODE, to allow withdrawal of a single control rod, provided the following requirements are met:

1. Two Source Range Monitors (SRM) are OPERABLE per Specification 3.10.B.1 and 3.10.B.2,

2. The Refuel Position One-Rod-Out Interlock is OPERABLE,

3. The "full-in" control rod position indication for each control rod is OPERABLE or the associated control rod drive is disarmed,

4. All other control rods are fully inserted, and

5.a The withdrawn control rod is OPERABLE, and Table 3.1.1, "Reactor Protection System (Scram) Instrumentation Requirement," channels for the following Trip Functions are OPERABLE as required for the Refuel MODE:
- IRM – High Flux
- IRM – Inoperative
- SDIV High Water Level – East
- SDIV High Water Level – West
- Mode Switch in Shutdown
- Manual Scram

OR

5.b All other control rods in a five by five array centered on the control rod being withdrawn are disarmed; at which time LCO 3.3.A.1, "Reactivity Margin – Core Loading," requirements may be changed to allow the single control rod withdrawn to be assumed to be the strongest control rod.

SURVEILLANCE REQUIREMENTS

4.14 SPECIAL OPERATIONS (continued)

C. Single Control Rod Withdrawal – Hot Shutdown

1. Two Source Range Monitors (SRM) are OPERABLE per Specification 4.10.B "Core Monitoring".

2. Perform functional test of the one-rod-out interlock weekly.

3. Each time the control rod is withdrawn from the "full-in" position, verify the control rod position indication has no "full-in" indication.

4. Verify all control rods, other than the control rod being withdrawn, are fully inserted every 24 hours.

5.a.1 Verify the Surveillance Requirements of Tables 4.1.1 and 4.1.2 for channels required to be OPERABLE for the Refuel MODE are performed as required,

5.a.2 Verify withdrawn control rod accumulator pressure is greater than minimum required every 7 days, and

5.a.3 Insert each withdrawn control rod at least one notch within 7 days after control rod is withdrawn and every 7 days thereafter.

OR

5.b Verify all control rods, other than the control rod being withdrawn, in a five by five array centered on the control rod being withdrawn, are disarmed every 24 hours.

LIMITING CONDITIONS FOR OPERATION

3.14 SPECIAL OPERATIONS (continued)

C. Single Control Rod Withdrawal – Hot Shutdown (continued)

Applicability

Hot Shutdown MODE with the reactor mode switch in Refuel position.

Actions

A. One or more of the above requirements not met,

1. Immediately initiate action to fully insert all insertable control rods,

AND

2. Place the reactor mode switch in the Shutdown position within 1 hour.

SURVEILLANCE REQUIREMENTS

4.14 SPECIAL OPERATIONS (continued)

C. Single Control Rod Withdrawal – Hot Shutdown (continued)

LIMITING CONDITIONS FOR OPERATION

3.14 SPECIAL OPERATIONS (continued)

D. Single Control Rod Withdrawal – Cold Shutdown

Specification

The MODE definition specified in Specification 1.0 for Cold Shutdown may be changed to include the reactor mode switch in the Refuel position, and operation considered not to be in Refuel MODE, to allow withdrawal of a single control rod, provided the following requirements are met:

1. Two source range monitors (SRM) are OPERABLE per Specification 3.10.B.1 and 3.10.B.2,

2.a The Refuel Position One-Rod-Out Interlock is OPERABLE, and the "full-in" control rod position indication for each control rod is OPERABLE or the associated control rod drive is disarmed,

OR

2.b A control rod withdrawal block is inserted,

3. All other control rods are fully inserted, and

4.a The withdrawn control rod is OPERABLE, and Table 3.1.1, "Reactor Protection System (Scram) Instrumentation Requirement," channels for the following Trip Functions are OPERABLE as required for the Refuel MODE:
- IRM – High Flux
- IRM – Inoperative
- SDIV High Water Level – East
- SDIV High Water Level – West
- Mode Switch in Shutdown
- Manual Scram

OR

4.b All other control rods in a five by five array centered on the control rod being withdrawn are disarmed; at which time LCO 3.3.A.1, "Reactivity Margin – Core Loading, "requirements may be changed to allow the single control rod withdrawn to be assumed to be the strongest control rod.

SURVEILLANCE REQUIREMENTS

4.14 SPECIAL OPERATIONS (continued)

D. Single Control Rod Withdrawal – Cold Shutdown

1. Two Source Range Monitors (SRM) are OPERABLE per Specification 4.10.B "Core Monitoring".

2.a Perform functional test of the one-rod-out interlock weekly. Additionally, each time the control rod is withdrawn from the "full-in" position, verify the control rod position indication has no "full-in" indication.

OR

2.b Verify a control rod block is inserted every 24 hours.

3. Verify all control rods, other than the control rod being withdrawn, are fully inserted every 24 hours.

4.a.1 Verify the Surveillance Requirements of Tables 4.1.1 and 4.1.2 for channels required to be OPERABLE for the Refuel MODE are performed as required, and

4.a.2 Verify withdrawn control rod accumulator pressure is greater than minimum required every 7 days, and

4.a.3 Insert each withdrawn control rod at least one notch within 7 days after control rod is withdrawn and every 7 days thereafter.

OR

4.b Verify all control rods, other than the control rod being withdrawn, in a five by five array centered on the control rod being withdrawn, are disarmed every 24 hours.

LIMITING CONDITIONS FOR OPERATION

3.14 SPECIAL OPERATIONS (continued)

D. Single Control Rod Withdrawal – Cold Shutdown (continued)

Applicability

Cold Shutdown MODE with the reactor mode switch in Refuel position.

Actions

A. With one or more of the above requirements not met with the affected control rod insertable,

1. Immediately initiate action to fully insert all insertable control rods,

AND

2. Place the reactor mode switch in the Shutdown position within 1 hour.

B. With one or more of the above requirements not met with the affected control rod not insertable,

1. Immediately suspend withdrawal of the control rod and removal of associated CRD,

AND

2.1 Immediately initiate action to fully insert all control rods.

OR

2.2 Immediately initiate action to satisfy the requirements of this LCO.

SURVEILLANCE REQUIREMENTS

4.14 SPECIAL OPERATIONS (continued)

D. Single Control Rod Withdrawal – Cold Shutdown (continued)

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.14 SPECIAL OPERATIONS (Continued)	4.14 SPECIAL OPERATIONS (Continued)
E. Multiple Control Rod Removal	E. Multiple Control Rod Removal
1. Any number of control rods and/or control rod drive mechanisms may be removed from the reactor pressure vessel provided that at least the following requirements are satisfied until all control rods and control rod drive mechanisms are reinstalled and all control rods are fully inserted in the core.	1. Within 4 hours prior to the start of removal of control rods and/or control rod drive mechanisms from the core and/or reactor pressure vessel and at least once per 24 hours thereafter until all control rods and control rod drive mechanisms are reinstalled and all control rods are fully inserted in the core, verify that:
a. The reactor mode switch is OPERABLE and locked in the Refuel position except that the position indication may be bypassed, as required, for those control rods and/or control rod drive mechanisms to be removed, after the fuel assemblies have been removed as specified below.	a. The reactor mode switch is OPERABLE and locked in the Refuel position.
b. Two source range monitors (SRM) are OPERABLE per Specification 3.10.B.1 and 3.10.B.2,	b. Two Source Range Monitors (SRM) are OPERABLE per Specification 4.10.B "Core Monitoring".
c. The Reactivity Margin requirements of Specifications 3.3.A.1 are satisfied.	c. The Reactivity Margin requirements of Specification 3.3.A.1 are satisfied.
d. No fuel is being loaded into the reactor core.	d. Deleted
e. All other control rods are fully inserted.	e. All other control rods are fully inserted.
f. The four fuel assemblies are removed from the core cell surrounding each control rod or control rod drive mechanism to be removed from the core and/or reactor vessel.	f. The four fuel assemblies surrounding each control rod and/or control rod drive mechanism that is to be removed from the reactor vessel at the same time are removed from the core and/or reactor vessel.

3.14 SPECIAL OPERATIONS (continued)

F. (Not Used)

4.14 SPECIAL OPERATIONS (continued)

F. (Not Used)

3.14 SPECIAL OPERATIONS (continued)

G. Control Rod Testing - Operating

Specification

The requirements of LCO 3.3.H, "Rod Pattern Control," may be suspended to allow performance of reactivity margin demonstrations, control rod scram time testing, control rod friction testing, and the Startup Test Program, provided:

1. The banked position withdrawal sequence requirements of SR 4.3.F.3 are changed to require the control rod sequence to conform to the specified test sequence,

OR

2. The RWM is bypassed; the requirements of LCO 3.3.F, "Rod Worth Minimizer," are suspended; and conformance to the approved control rod sequence for the specified test is verified by a second licensed operator or other qualified member of the technical staff.

Applicability

Run MODE and startup MODE with the requirements of LCO 3.3.H not met.

Actions

Above requirements not met immediately suspend performance of the test and exception to LCO 3.3.H.

4.14 SPECIAL OPERATIONS (continued)

G. Control Rod Testing - Operating

1. Prior to control rod movement, verify control rod sequence input to the RWM is in conformance with the approved control rod sequence for the specified test,

OR

2. During control rod movement, verify movement of control rods is in compliance with the approved control rod sequence for the specified test by a second licensed operator or other qualified member of the technical staff.

4.0 DESIGN FEATURES

4.1 Site Location

Pilgrim Nuclear Power Station is located on the western shore of Cape Cod Bay in the Town of Plymouth, Plymouth County, Massachusetts and contains approximately 517 acres owned by Entergy Nuclear as shown on FSAR Figures 2.2-1 and 2.2-2. The site boundary is posted and a perimeter security fence provides a distinct security boundary for the protected area of the station.

The reactor (center line) is located approximately 1800 feet from the nearest property boundary.

4.2 Deleted

4.3 Fuel Storage

4.3.1 <u>Criticality</u>

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum k-infinity of 1.32 for standard core geometry, calculated at the burnup of maximum bundle reactivity, and an average U-235 enrichment of 4.6 % averaged over the axial planar zone of highest average enrichment; and

b. $K_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 10.3.5 of the FSAR.

(continued)

4.0 DESIGN FEATURES

4.3 Fuel Storage (continued)

4.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. K_{eff} ≤0.95 if fully flooded with water, which includes an allowance for uncertainties as described in Section 10.2.5 of the FSAR;

b. K_{eff} ≤0.90 when dry, which includes an allowance for uncertainties as described in Section 10.2.5 of the FSAR; and

c. A nominal 6.60 inch center to center distance between fuel assemblies placed in storage racks.

4.3.2 Drainage

The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 115 ft.

4.3.3 Capacity

The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 3859 fuel assemblies .

4.3.4 Heavy Loads

a. Loads in excess of 2000 lb. shall be prohibited from travel over fuel assemblies in the spent fuel storage pool with the exception that heavy load handling over irradiated fuel in the Multi-Purpose Canister is permitted using a single-failure-proof handling system.

b. No fuel which has decayed for less than 200 days shall be stored in racks within an arc described by the height of the cask around the periphery of the leveling platform during cask handling operations in the spent fuel pool or when a cask is in the spent fuel pool.

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The plant manager shall be responsible for overall facility operation and shall delegate in writing the succession to this responsibility during his absence.

The plant manager or his designee shall approve, prior to implementation, each proposed test, experiment, or modification to systems or equipment that affect nuclear safety.

5.1.2 The control room supervisor (CRS) shall be responsible for the shift command function.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for facility staff and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear fuel.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements, including the plant-specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications, shall be documented in the Pilgrim Station Final Safety Analysis Report (FSAR);

b. The plant manager shall be responsible for overall safe operation of the facility and shall have control over those onsite activities necessary for safe storage and maintenance of the nuclear fuel;

c. The specified corporate officer for Pilgrim shall have corporate responsibility for the safe storage and handling of nuclear fuel and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the facility to ensure safe management of nuclear fuel; and

d. The individuals who train the CERTIFIED FUEL HANDLERS, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their ability to perform their assigned functions.

5.2.2 Facility Staff

The facility staff organization shall include the following:

a. Each duty shift shall be composed of at least one control room supervisor and one NON-CERTIFIED OPERATOR. The NON-CERTIFIED OPERATOR position may be filled by a CERTIFIED FUEL HANDLER.

(continued)

5.2 Organization

5.2.2 Facility Staff (continued)

b. At least one person qualified to stand watch in the control room (NON-CERTIFIED OPERATOR or CERTIFIED FUEL HANDLER) shall be present in the Control Room when nuclear fuel is stored in the spent fuel pool.

c. Oversight of fuel handling operations shall be provided by a CERTIFIED FUEL HANDLER.

d. Shift crew composition may be less than the minimum requirement of 5.2.2.a for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements and all of the following conditions are met:

   1) No fuel movements are in progress;

   2) No movement of loads over fuel are in progress; and

   3) No unmanned shift positions during shift turnover shall be permitted while the shift crew is less than the minimum.

e. Deleted

f. An individual qualified in radiation protection procedures shall be on site during fuel handling operations and during movement of heavy loads over the fuel storage racks. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

g. Deleted

h. The control room supervisor shall be a CERTIFIED FUEL HANDLER.

i. Deleted

5.0 ADMINISTRATIVE CONTROLS

5.3 Facility Staff Qualifications

5.3.1 Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-1978 for comparable positions with exceptions specified in the Quality Assurance Program Manual (QAPM).

5.3.2 An NRC approved training and retraining program for CERTIFIED FUEL HANDLERs shall be maintained.

5.0 ADMINISTRATIVE CONTROLS

5.4 Procedures

5.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

a. The procedures applicable to the safe storage of nuclear fuel recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978;

b. Deleted

c. Quality assurance for effluent and environmental monitoring;

d. Fire Protection Program implementation; and

e. All programs specified in Specification 5.5.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs and Manuals

The following programs shall be established, implemented and maintained.

5.5.1 Offsite Dose Calculation Manual (ODCM)

a. The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and

b. The ODCM shall also contain the radioactive effluent controls and radiological environmental monitoring activities and descriptions of the information that should be included in the Annual Radiological Environmental Operating, and Radioactive Effluent Release, reports required by Specification 5.6.2 and Specification 5.6.3.

Licensee initiated changes to the ODCM:

a. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

   1. sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s), and

   2. a determination that the change(s) maintain the levels of radioactive effluent control required by 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations;

b. Shall become effective after the approval of the plant manager; and

c. Shall be submitted to the NRC in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Radioactive Effluent Release Report for the period of the report in which any change in the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

(continued)

5.5 Programs and Manuals

5.5.2 Deleted

5.5.3 Not Used

5.5.4 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM;

(continued)

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to ten times the concentration values in Appendix B, Table 2, Column 2 to 10 CFR 20.1001-20.2402;

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site boundary to areas at or beyond the site boundary conforming to the following:

   1. For noble gases: Less than or equal to 500 mrem/yr to the whole body and less than or equal to 3000 mrem/yr to the skin, and

   2. For Iodine-131, Iodine-133, Tritium, and all radionuclides in particulate form with half-lives greater than 8 days: Less than or equal to 1500 mrem/yr to any organ.

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

(continued)

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

i. Limitations on the annual and quarterly doses to a member of the public from Iodine-131, Iodine-133, Tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public, beyond the site boundary, due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track the FSAR Section C.3.4.1, cyclic and transient occurrences to ensure that components are maintained within the design limits.

5.5.6 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. a change in the TS incorporated in the license; or

2. a change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of Specification 5.5.6b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5 Programs and Manuals

5.5.7 Configuration Risk Management Program (CRMP)

CRMP provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to technical specification structures, systems, or components for which a risk-informed allowed outage time has been granted.

The CRMP includes the following elements:

a. Provisions for the control and implementation of a Level 1 at power internal event PRA-informed methodology. The assessment is capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the LCO Action Statement for preplanned activities.

c. Provisions for performing an assessment after entering the LCO Action Statement for unplanned entry into the LCO Action Statement activities.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Action Statement.

e. Provisions for considering other applicable risk significant contributors such as Level 2 issues and external events, quantitatively or qualitatively.

5.5.8 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Main Control Room Heating, Ventilation and Air Conditioning System, CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem whole body or its equivalent to any part of the body 5 rem total effective dose equivalent (TEDE) for the duration of the accident. The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197.

"Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one subsystem of the MCREC System, operating at the flow rate required by the VFTP, at a Frequency of 24 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the 24 month assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. Each Surveillance Requirement shall be performed within the specified SURVEILLANCE INTERVAL with a maximum allowable extension not to exceed 25 percent of the specified SURVEILLANCE INTERVAL. The SURVEILLANCE INTERVAL requirement is applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

5.5.9 Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)

a. RCS pressure and temperature limits for heatup, cool-down, low temperature operation criticality and hydrostatic testing as well as heatup and cool-down rates shall be established and documented in the PTLR for the following:

i) Limiting conditions for Operation Section 3.6.A.2

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following document:

i) SIR-05-044-A "Pressure-Temperature Limits Report Methodology for Boiling Water Reactors", April 2007

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any reason or supplement thereto.

(continued)

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 Not Used

5.6.2 Annual Radiological Environmental Operating Report

The Annual Radiological Environmental Operating Report covering the operation of the facility during the previous calendar year shall be submitted by May 15 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include a summary of the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

(Continued)

5.6 Reporting Requirements

5.6.3 Radioactive Effluent Release Report

The Radioactive Effluent Release Report covering the operation of the facility shall be submitted in accordance with 10 CFR 50.36a by May 15th of each year. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the facility. The material provided shall be consistent with the objectives outlined in the ODCM and process control procedures and in conformance with 10 CFR 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

5.6.4 Not Used

5.6.5 Core Operating Limits Report (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. Table 3.1.1 – APRM High Flux trip level setting
2. Table 3.2.C –APRM Upscale trip level setting
3. 3.11.A – Average Planar Linear Heat Generation Rate (APLHGR)
4. 3.11.B – Linear Heat Generation Rate (LHGR)
5. 3.11.C –Minimum Critical Power Ratio (MCPR)
6. 3.11.D – Power/Flow Relationship During Power Operation

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," (through the latest NRC approved amendment at the time the reload analyses are performed as specified in the COLR).

(Continued)

5.6 Reporting Requirements

5.6.5 (continued)

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as shutdown margin, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

5.7.1 Pursuant to 10 CFR 20, paragraph 20.1601(c), in lieu of the requirements of 10 CFR 20.1601, each high radiation area, as defined in 10 CFR 20, in which the intensity of radiation is $>$ 100 mrem/hr but $<$ 1000 mrem/hr, shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP). Individuals qualified in radiation protection procedures (e.g., radiation protection personnel) or personnel continuously escorted by such individuals may be exempt from the RWP issuance requirement during the performance of their assigned duties in high radiation areas with exposure rates $\leq$ 1000 mrem/hr, provided they are otherwise following facility radiation protection procedures for entry into such high radiation areas.

Any individual or group of individuals permitted to enter such areas shall be provided with or accompanied by one or more of the following:

a. A radiation monitoring device that continuously indicates the radiation dose rate in the area.

b. A radiation monitoring device that continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel are aware of them.

c. An individual qualified in radiation protection procedures with a radiation dose rate monitoring device, who is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by the radiation protection manager in the RWP.

5.7.2 In addition to the requirements of Specification 5.7.1, areas with radiation levels $\geq$ 1000 mrem/hr shall be provided with locked or continuously guarded doors to prevent unauthorized entry and the keys shall be maintained under the administrative control of the control room supervisor on duty or radiation protection supervision. Doors shall remain locked except during periods of access by personnel under an approved RWP that shall specify the dose rate levels in the immediate work areas and the maximum allowable stay times for individuals in those areas. In lieu of the stay time specification of the RWP, direct or remote (such as closed circuit TV cameras) continuous surveillance may be made by personnel qualified in radiation protection procedures to provide positive exposure control over the activities being performed within the area.

(Continued)

5.7 High Radiation Area

5.7.3 For individual high radiation areas with radiation levels of > 1000 mrem/hr, accessible to personnel, that are located within large areas such as reactor containment, where no enclosure exists for purposes of locking, or that cannot be continuously guarded, and where no enclosure can be reasonably constructed around the individual area, that individual area shall be barricaded and conspicuously posted, and a flashing light shall be activated as a warning device.

APPENDIX B

ADDITIONAL CONDITIONS

OPERATING LICENSE NO. DPR-35

Entergy Nuclear Operations, Inc. shall comply with the following conditions on the schedules noted below:

Amendment Number	Additional Conditions	Implementation Date
177	The licensee is authorized to relocate certain Technical Specifications requirements to licensee-controlled documents. Implementation of this amendment shall include relocation of various sections of the technical specifications to the appropriate documents as described in the licensee's application dated September 19, 1997, and in the staff's safety evaluation attached to this amendment.	The amendment shall be implemented within 30 days from July 31, 1998, except that the licensee shall have until the next scheduled Updated Final Safety Analysis Report (UFSAR) update to incorporate the UFSAR relocations.

Office of the Inspector General

U.S. Nuclear Regulatory Commission
Defense Nuclear Facilities Safety Board

Audit of NRC's Transition Process for Decommissioning Power Reactors

OIG-19-A-16
August 23, 2019

All publicly available OIG reports (including this report) are accessible through NRC's Web site at
http://www.nrc.gov/reading-rm/doc-collections/insp-gen

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

OFFICE OF THE
INSPECTOR GENERAL

August 23, 2019

MEMORANDUM TO: Margaret M. Doane
Executive Director for Operations

FROM: Dr. Brett M. Baker ***/RA/***
Assistant Inspector General for Audits

SUBJECT: AUDIT OF NRC'S TRANSITION PROCESS FOR DECOMMISSIONING POWER REACTORS (OIG-19-A-16)

Attached is the Office of the Inspector General's (OIG) audit report titled *Audit of NRC's Transition Process for Decommissioning Power Reactors*.

The report presents the results of the subject audit. Following the August 13, 2019, exit conference, agency staff indicated that they had no formal comments for inclusion in this report.

Please provide information on actions taken or planned on each of the recommendation(s) within 30 days of the date of this memorandum. Actions taken or planned are subject to OIG follow-up as stated in Management Directive 6.1.

We appreciate the cooperation extended to us by members of your staff during the audit. If you have any questions or comments about our report, please contact me at (301) 415-5915 or Jacki Storch, Team Leader, at (301) 415-2877.

Attachment: As stated

Office of the Inspector General

U.S. Nuclear Regulatory Commission
Defense Nuclear Facilities Safety Board

OIG-19-A-16
August 23, 2019

Results in Brief

Why We Did This Review

Decommissioning is the process used to safely remove a nuclear power plant from service and reduce residual radioactivity to a level that permits release of the property and termination of its NRC operating license.

The Office of Nuclear Reactor Regulation (NRR) maintains oversight of all operating nuclear power plants. The Office of Nuclear Material Safety and Safeguards (NMSS) maintains oversight of all decommissioning activities. Once a licensee announces its intention to shut down its reactor, NRR and NMSS closely coordinate during this "operating to decommissioning" transition process.

The audit objective was to determine whether NRC's transfer of oversight responsibilities, used when operating power reactors undergo decommissioning, is efficient and effective.

Audit of NRC's Transition Process for Decommissioning Power Reactors

What We Found

OIG found that NRC's transfer of oversight responsibilities is effective; however, the efficiency could be improved. Specifically, NRC should update decommissioning guidance and implement a formal project manager knowledge transfer process.

Agency guidance states NRC should run its programs effectively and efficiently; however, NRC has not implemented certain knowledge management principles into the reactor decommissioning process. Consequently, there may be unnecessary delays in the processing and management of reactor decommissioning projects which may incur additional costs to licensees, NRC, and taxpayers.

What We Recommend

This report makes two recommendations to improve the effectiveness and efficiency of the transition from operating to decommissioning power reactors.

Agency Management stated their general agreement with the finding and recommendations of this report.

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APPENDIXES

ABBREVIATIONS AND ACRONYMS

NRC	Nuclear Regulatory Commission
PSDAR	Post-Shutdown Decommissioning Activities Report
NRR	Office of Nuclear Reactor Regulation
NMSS	Office of Nuclear Material Safety and Safeguards
PM	Project Manager

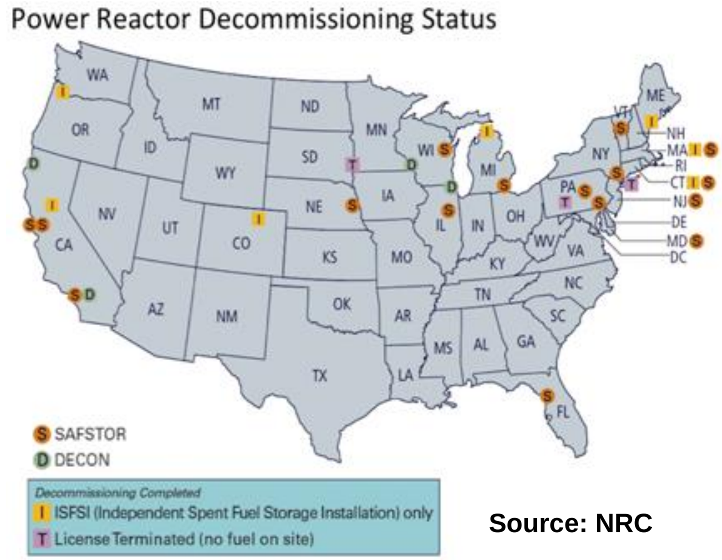
I. BACKGROUND

The U.S. Nuclear Regulatory Commission (NRC) regulates the decommissioning of commercial nuclear power plants. Decommissioning is the process used to safely remove a nuclear power plant from service and reduce residual radioactivity to a level that permits release of the property and termination of its NRC operating license. NRC has rules governing commercial nuclear power plant decommissioning involving the cleanup of radioactively contaminated plant systems and structures and removal of the radioactive fuel. These rules protect workers and the public during the entire decommissioning process and protect the public after the license is terminated.

As of June 2019, there are 20 nuclear power reactors undergoing decommissioning regulated by NRC (see Figure 1). Licensees in the U.S. have utilized two[1] primary methods of decommissioning: "DECON" and "SAFSTOR." Under the "DECON" method, soon after the plant closes, equipment, structures, and portions of the plant are immediately removed or decontaminated. Under the "SAFSTOR" method, a nuclear power plant is maintained and monitored to allow radioactivity to decay; afterward, the plant is dismantled and the property is decontaminated. The entire decommissioning process may take up to 60 years. For a map of sites that have completed decommissioning or are undergoing decommissioning, see Figure 1.

[1] A third method of decommissioning available to licensees called "entomb" involves the permanent encasement of radioactive contaminants in structurally sound material such as concrete. To date, no NRC-licensed facilities have implemented this option.

Figure 1: Decommissioned Plants & Plants Undergoing Decommissioning as of June 2019.[2]



Source: NRC

Decommissioning Process

When a nuclear power plant licensee has determined to shut down a plant permanently, it must submit a written certification of this decision to NRC within 30 days. When all nuclear fuel is permanently removed from the reactor vessel, the licensee must also submit a written certification of permanent fuel removal to NRC. Upon NRC's receipt of both certifications, the licensee is no longer authorized to operate the reactor or load fuel into the reactor vessel. Prior to or within 2 years after the licensee permanently ceases operations, the licensee must submit a post-shutdown decommissioning activities report (PSDAR) to NRC. This report provides a description of the planned decommissioning activities, a schedule for accomplishing them, and an estimate of the expected costs.

NRC's goal is to make the report available for public review and comment and hold a public meeting near the reactor within 90 days of receiving the PSDAR. The licensee may begin major decommissioning activities 90 days after it has submitted the PSDAR and both required certifications. Major decommissioning activities can include permanent removal of major components like the reactor vessel, steam generators, and large piping systems, pumps, and valves. At least 2 years before the expected license termination, the licensee is required to submit a license termination plan for NRC's approval. This plan addresses site characterization and site remediation, final radiation surveys, and site release, among others.

[2] There are 10 decommissioned reactors as indicated by the "Independent Spent Fuel Storage Installation" and "License Terminated" sites. The map displays an additional 20 reactors currently undergoing the decommissioning process. San Onofre Nuclear Generating Station, Units 2 and 3, and Zion Nuclear Power Station, Units 1 and 2, are currently in active decommissioning.

Handoff of Oversight Responsibilities

The Office of Nuclear Reactor Regulation (NRR) maintains oversight of all operating nuclear power plants. The Office of Nuclear Material Safety and Safeguards (NMSS) maintains oversight of all decommissioning activities. Once a licensee announces its intention to shut down its reactor, NRR and NMSS closely coordinate during this "operating to decommissioning" transition process.[3] This process begins when the licensee announces its plans to permanently shut down the plant. This transition process includes the two certifications licensees must submit to NRC, as well as the PSDAR submission, and any license amendments and exemptions that must be approved by NRR and/or NMSS staff. Once these items have been completed and the updated defueled technical specifications[4] are approved by NRR, the official handoff to NMSS occurs. This completes the NRC's transition of its oversight of the plant from an operating reactor to a decommissioning facility, and NMSS now has full responsibility of the power reactor and oversees the remainder of the decommissioning.

License Amendments & Exemptions

One of NRC's primary responsibilities during the operating to decommissioning transition process is the review of licensee amendment and exemption requests. Currently, most of NRC's regulations do not specifically address reactor decommissioning. Specifically, many of NRC's regulations and some conditions of the license hold decommissioning reactors to the same standard, and the same requirements, as operating reactors. This includes employing the same number of emergency response staff, or maintaining the same physical security requirements, even after the site has shut down and there is no longer fuel in the reactor core. Consequently, after licensees announce their intent to decommission, they will submit several requests for NRC's

[3] NRR still has primary oversight responsibilities during this point in the transition process.

[4] Technical specifications are part of an NRC license authorizing the operation of a power plant. They establish requirements for items such as safety limits, surveillance requirements, design features, and administrative controls. When a licensee begins the decommissioning process, its standard technical specifications are updated to defueled technical specifications to reflect the decommissioning status of the power reactor.

review to exempt them from regulations that primarily apply to operating reactors and amend their licenses to align with planned decommissioning activities rather than reactor operations. NRC has approved such requests based on the much lower risk with decommissioning reactors, as compared to operating reactors, due to the nuclear fuel being removed. Nevertheless, the process for preparing and reviewing these exemption and amendment requests requires a commitment of resources by both the licensee and NRC staff.

Pictured: Connecticut Yankee during the decommissioning process.

Source: NRC

Decommissioning Reactor Rulemaking

Beginning in the late 1990s, it became apparent to NRC that it should consider rulemaking to improve the efficiency and effectiveness of the power reactor decommissioning process. A decommissioning rulemaking effort was initiated to address the transition issues, but it was subsequently suspended because of a shift in agency priorities following the terrorist attacks on September 11, 2001. However, in 2014, the Commission directed NRC staff to proceed with rulemaking on reactor decommissioning. Major provisions of the proposed rule include changes in areas such as emergency preparedness, physical security, cyber security, drug and alcohol testing, certified fuel handler training, and foreign ownership, among others. If the proposed rule's current iteration is approved, it would streamline the decommissioning process and eliminate approximately 13 licensing actions (e.g., exemptions and amendments) per decommissioning that NRC staff must process. NRC staff submitted the draft proposed rule to the Commission for review in May 2018.

II. OBJECTIVE

To determine whether NRC's transfer of oversight responsibilities, used when operating power reactors undergo decommissioning, is efficient and effective. Appendix A contains information on the audit scope and methodology.

III. FINDING

NRC's transfer of oversight responsibilities is effective; however, the efficiency could be improved. Specifically, NRC should

- Update decommissioning guidance, and
- Implement a formal project manager knowledge transfer process.

A. Efficiency of NRC Decommissioning Practices Could be Improved

Though effective, NRC's decommissioning process could be more efficient. Agency guidance states NRC should run its programs effectively and efficiently; however, NRC has not implemented certain knowledge management principles into the reactor decommissioning process. Consequently, there may be unnecessary delays in the processing and management of reactor decommissioning projects which may incur additional costs to licensees, NRC, and taxpayers.

What Is Required

Agency guidance states NRC should run its programs effectively and efficiently.

Project Aim seeks to enhance the culture of NRC to increase efficiency, effectiveness, agility, and flexibility of NRC work processes. NRC's goal is to improve agency processes by streamlining, standardizing, and clarifying roles and responsibilities so that resources are used more wisely.

What We Found

Though effective, NRC's decommissioning process could be more efficient.

Currently, there is no standard method to decommission power reactors as the process is dynamic and there are many variables involved. NRC is still adjusting to the changes occurring in reactor decommissioning space, and this is further exacerbated by the lack of updated agency guidance and the absence of a reactor decommissioning knowledge transfer process for NRC staff.

<u>Recent History</u>

Starting in early 2013 and through the end of 2014, five power reactors permanently ceased operations. These were the first reactors to transition to decommissioning since 1998. Out of the five power reactor shutdowns, four were unexpected and involved little pre-planning by licensees and NRC. Because it had been 15 years since any reactor had entered decommissioning, licensees and NRC staff initially had limited experience in processing decommissioning licensing actions. Furthermore, NRC's regulations were generally not written to address reactor decommissioning.

From 2013 through 2015, NRC had to process over 70 decommissioning-related licensing actions and other regulatory activities for the five decommissioning reactors. Since the last round of decommissionings, process changes occurred including the need to review and process multiple concurrent licensing action applications (from multiple licensees). From a knowledge management perspective, licensees and NRC staff were both working on steep learning curves.

NRC formed a decommissioning working group to study and document these recent decommissionings, as well as to develop a lessons learned report[5] to assist in future power reactor decommissionings.

New Business Model

In October 2018, NRC staff issued an order approving the permanent license transfer of the Vermont Yankee operating license from the original owner (Entergy) to a new decommissioning company (NorthStar). The idea behind this new business model is decommissioning companies possess the required expertise and can complete the decommissioning process more quickly and efficiently than the company that operated the reactor. These transactions typically include switching the licensee's decommissioning plan from SAFSTOR to DECON, thereby potentially reducing the decommissioning timeline from 60 years down to possibly 10 years. According to NRC staff, this business model appears to be the "wave of the future" and NRC is currently reviewing several other license transfer requests of this kind. Because this new business model presents a compressed decommissioning time frame, and each power reactor is different and presents its own unique challenges, NRC is still learning how to work with these types of license transfer requests.

NRC Billing Practices During the Transition Period

The audit team analyzed NRC's billing practices; specifically, to identify if there may have been incorrect licensee billing during the transition period when both NRR and NMSS were involved in the reactor decommissioning

[5] *Power Reactor Transition from Operations to Decommissioning,* Lessons Learned Report, October 2016. Henceforth, this report shall be referred to as the *Lessons Learned Report.*

process. The audit team reviewed raw cost activity code data provided by the Office of the Chief Financial Officer to evaluate whether there may have been overlap in licensee fee billing during the transition period between NRR and NMSS. The audit team also reviewed the agency's forecasted number of full-time equivalents to be used for decommissioning activities and compared it with the number expended to identify any possible large discrepancies. The data analysis did not indicate any evidence of unjustified billing charges or unreasonable fluctuations in full-time equivalents during reactor decommissioning. In fact, the data analysis displayed strong coordination between the two program offices, and this was further supported by interviews with licensees. See Appendix B for NRR and NMSS billing hours data analyses.

Why This Occurred

NRC has not incorporated certain knowledge management principles for reactor decommissioning.

Two basic knowledge management[6] principles, guidance and knowledge transfer, have not been effectively implemented into NRC's power reactor decommissioning processes.

<u>Guidance</u>

Both NRR and NMSS' office guidance documents related to power reactor decommissioning are outdated. NRR's guidance document, Office Instruction-COM 101, was last updated in 2002. NMSS' guidance document, Policy & Procedure 5-1, was last updated in 2016. However, this update simply addressed an office name change due to an internal reorganization, and this document has seen little substantive revision since it was originally written in 2007.[7] Additionally, Regulatory Guide

[6] Knowledge management is a practical, process-orientated approach to how agencies and departments capture institutional knowledge and learn from it. Knowledge management ensures that all necessary elements (accountabilities, processes, technologies, and governance) are in place and interconnected. This ensures that there are no gaps in the system, and that knowledge flows freely through the organization.

[7] Policy & Procedure 5-1 was revised in 2010, but the revision clarified NRC's financial assurance review responsibilities which is outside the scope of this audit.

1.184, which provides guidance to licensees on the actions required to decommission power reactors, was last updated in 2013.

Despite the evolution of the decommissioning process, these primary guidance documents remained largely unchanged since their initial inception. Not surprisingly, some staff stated that the guidance documents are unclear or lacking in detail. For example, one staff member said the guidance does not meet reality as there is no orderly flow of licensing actions as depicted in guidance. Rather, licensing actions can occur in an ad hoc manner. A staff member from one of NRC’s regional offices opined that NRC’s guidance documents do not clearly state how the handoff from NRR to NMSS is to occur. This person said the guidance should capture examples, people's experiences, etc., because regional staff do not have that knowledge.

Some other examples where the guidance is unclear include

- NMSS involvement – How and when should NMSS staff be involved with the power reactor decommissioning process? It is clear to most that NMSS has oversight responsibility after NRR has approved the defueled technical specifications, but some NMSS staff opined that they were not involved early enough in the process prior to the approval of the new technical specifications. This leads them to be less informed when their responsibilities eventually increase. This could differ for each reactor and depends on the project managers (PMs) involved, but it likely occurs because there is no set standard for NMSS involvement provided in guidance. For example, staff raised questions as to when the operating to decommissioning transition process technically begins since there is no precise order of decommissioning activities; what incomplete reviews NRR can pass on to NMSS; and which office has the lead in stakeholder activities.

Pictured: NRC public meeting.

Source: NRC

- PSDAR public meetings – Who should run these meetings? Since NMSS staff are the decommissioning experts, they are expected to run the public PSDAR meetings. However, at times this meeting occurs prior to the handoff of decommissioning responsibilities from NRR to NMSS. Furthermore, funding for these meetings comes from NRR's budget. Consequently, there have been instances of confusion over which office oversees this meeting. There have also been occasions when NRR and NMSS did not always agree on certain aspects of how and when NRC should run the meeting.

- New business model (decommissioning license transfers) – How should NRC address these requests? Since decommissioning license transfers are new (2018), NRC's guidance does not address them. For example, staff mentioned a recent license transfer request has posed some logistical problems. A licensee recently submitted its PSDAR simultaneously with a license transfer request, the PSDAR of the proposed decommissioning company, and related exemptions for both entities. The licensee also asked for it to be completed on an expedited basis. This strained NRC resources since staff had to review everything at once, to include the review of the PSDAR and exemption requests from an entity that was not yet the licensee.

  This poses a challenge as staff is reviewing the PSDAR of a proposed decommissioning company prior to NRC's approval of the license transfer; thus, NRC could potentially be expending resources on a license transfer that may not be approved. On the other hand, licensees and decommissioning companies may prefer to submit both PSDARs upfront because PSDARs contain company financial information necessary to approve any license transfers. Nevertheless, PSDARs from current licensees and from decommissioning companies are usually much different, with licensees typically choosing SAFSTOR and decommissioning

companies choosing DECON. Currently, NRC regulations permit licensees and decommissioning companies to submit their requests concurrently.

Lessons Learned Report

Both NRC staff and licensees state the *Lessons Learned Report* is an excellent resource and has the most up-to-date information on power reactor decommissioning. The report provides lessons learned on several decommissioning experiences and provides several recommendations. For example, the report encourages licensees to submit planned, early decommissioning transition licensing actions to increase the efficiency of the operating to decommissioning transition process. It noted that decommissioning guidance is outdated, especially in areas of document processing and office structure. It also stated the experience gained in recent decommissioning transitions should be used to improve Regulatory Guide 1.184. The report recommended NRC staff proceduralize numerous different activities, including planning discussions with licensees related to the sequencing of PSDAR submittals and encouraging licensees to submit a decommissioning physical security plan amendment 1 year prior to shutting down the plant. To date, none of the report's recommendations have been incorporated into NRC-issued guidance.[8]

Knowledge Transfer

In addition to guidance, another important basic knowledge management principle centers around knowledge transfer. Presently, NRR and NMSS do not have a formal knowledge transfer process for decommissioning power reactors.

One NRR staff member said there is one experienced PM in NRR and the lack of a knowledge transfer process is a weak area. An NRR PM opined there should be a system for new PMs to shadow the experienced PM, but this does not typically occur. An NMSS PM said knowledge transfer could be a major issue moving forward, given several senior staff involved with decommissionings are close to retirement. Another NMSS PM stated

[8] NRC staff has made proposed changes to several guidance documents to address the proposed rule changes and lessons learned.

NMSS' training focuses on the "end of the decommissioning" process and not on power reactor licensing or operations in general, thereby leaving out the operating to decommissioning transition process.

The audit team reviewed the turnover of primary PMs for the six power reactor sites currently undergoing decommissioning activities. Of these six sites that began their operating to decommissioning activities in 2012 or later, there have been at least 29 different PMs assigned to those sites.

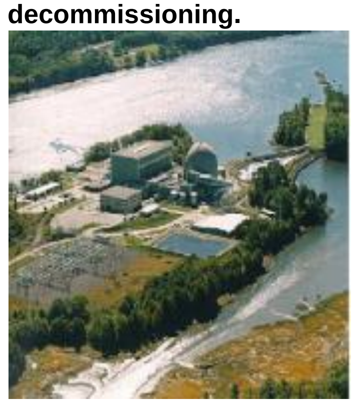
Though NRC does not have a formal knowledge transfer process, NRR has recognized a need for increased training and is in the process of adding a "transition to decommissioning" qualification card to its qualification program for NRR PMs. NMSS has facility decommissioning training as well as a qualification program for its PMs.

Why This Is Important

There may be unnecessary delays in the processing and management of reactor decommissioning projects.

The lack of certain knowledge management principles could create unnecessary delays in decommissioning power reactors. One example of an issue with employee turnover and the lack of proper knowledge transfer was provided by a licensee. The licensee stated that in October of 2018, NRC had said it would consult with another Federal agency regarding a requirement that the licensee felt should no longer apply. This consultation was supposed to be completed by June 2019. When the licensee contacted NRC in March 2019 for an update, NRC told the licensee that the original PM was no longer with NRC, and the new PM was unaware of the

Pictured: Maine Yankee before and after decommissioning.



Source: NRC

situation. The new PM began working on the issue, but the work on this item has now been delayed 6 months.

As noted in the *Lessons Learned Report*, the decommissioning working group asserted that the current exemption and amendment processes for transitioning plants are sufficient to ensure adequate protection of public health and safety and of the environment and are consistent with the common defense and security. However, the process is inefficient and additional delays could incur more costs to licensees, NRC, and taxpayers, and could further delay releasing reactor sites to the public for unrestricted use.[9]

Rulemaking

As noted earlier, a draft decommissioning rule is under review by the Commission, which would streamline the power reactor decommissioning process and potentially save millions of dollars by removing approximately 13 of the typical exemption requests and licensing actions. NRC estimates the new rule would save licensees, NRC, and taxpayers approximately $19 million per decommissioning power reactor. An industry representative stated that there is a real cost to decommissioning delays, to the tune of approximately $1 million per month per every 100 staff employed.

The audit team conducted a data review of the exemptions and licensing actions from 2017 to 2019 that would be eliminated by the new decommissioning rule. The audit team found that there was a total of 14 licensing actions over the past 2 years that averaged just over 7 months each to complete, and a total of approximately 2,125 hours expended by NRC staff for the 14 licensing actions. Furthermore, NRC estimates a savings of approximately 1.25 full-time equivalents per power reactor under the new rulemaking.

The vast majority of NRC staff, as well as industry representatives, interviewed by the audit team agreed that the new rule would make the

[9] In addition to releasing former nuclear power plants for the general public's use, licensees may also release the site for other purposes such as industrial uses (e.g., leaving buildings and installing a gas-, coal-, or oil-powered generating plant).

reactor decommissioning process much more efficient. Moreover, in a 2017 congressional hearing,[10] the Commission asserted that a new rule would promote more transparency and accountability than NRC's current system of granting exemptions to licensees. An industry representative stated that the decommissioning process is very inefficient right now, noting it is hard to believe just how many exemptions and license change requests licensees must submit. An NRC senior staff member opined that a majority of the work NRR must do is to exempt licensees from provisions that "are unnecessary." This person noted that NRR spends a lot of time doing extraneous work on regulatory requirements not necessary for safety, but just to meet "the letter of the law." The employee stated if the rulemaking goes through, NRR could focus on things that are more significant.

NRC has developed guidance and established agencywide principles that appear to support the new rulemaking. In its *Lessons Learned Report*, the decommissioning working group stated that "most of the licensee exemption and amendment requests do not involve safety issues and are based instead on efficiencies gained and the associated reduction of licensee resources required for a plant that is no longer operating." It continued, "NRC staff recognizes that the continued need for exemptions by licensees transitioning to decommissioning reflects a gap in the regulatory structure." It also noted, "Use of regulatory exemptions has several drawbacks when compared to having explicit regulations applicable to decommissioning plants, such as not being as efficient or predictable and not providing for public comment." Furthermore, *NRC's Principles of Good Regulation* state that regulatory activities which minimize the use of resources should be adopted, and regulatory decisions should be made without undue delay.

The draft rule has been with the Commission for over a year, and there is no indication as to when the Commission may vote on it. One commissioner publicly expressed concerns with the proposed rule in May 2019, while another implied to the audit team that the rulemaking was not a top priority.

[10] *Oversight of the Nuclear Regulatory Commission, Hearing before the Committee on Environment and Public Works*; December 13, 2017.

Conclusion

Seven reactor facilities have recently begun the decommissioning process,[11] and nine more have announced plans to start decommissioning from 2019 to 2025. See Appendix C for nuclear power plants with announced planned shutdowns from 2019 to 2025. The number of power reactors planning to decommission is sharply increasing, while the length of time to complete the decommissionings is sharply decreasing due to the current trend of the new license transfer business model.

Since more decommissionings are imminent, NRC must be properly equipped to handle these activities. This includes ensuring guidance is clear and updated, as well as establishing a formal staff knowledge transfer process. According to an NRC Office Director, there is a "talent crisis" within NRC as much of the agency's staff is ready to retire.[12] NRC must be prepared for impending staff retirements and turnover to effectively handle the influx of expected reactor decommissionings.

The audit team has found that NRC has done an effective job in working with licensees during the decommissioning process. While efficiencies could certainly be gained through improved guidance and a focus on knowledge transfer, perhaps the most significant improvement to the effectiveness and efficiency of the reactor decommissioning process would be the implementation of the proposed decommissioning rule.

Recommendations

OIG recommends that the Executive Director for Operations

1. Update NRR and NMSS decommissioning guidance to include the license transfer business model, the applicable

[11] These facilities are Crystal River, Kewaunee, Oyster Creek, Vermont Yankee, Fort Calhoun, and San Onofre, Units 2 and 3.

[12] At a Commission briefing on June 18, 2019, NRC's Chief Human Capital Officer said the rate of retirement eligibility is increasing, with 26 per cent of NRC's population eligible to retire by the end of fiscal year 2019. Moreover, approximately 40 per cent of the agency's workforce will be eligible to retire by 2022.

items/recommendations of the *Lessons Learned Report*, and to further clarify the operating to decommissioning transition process.

2. Create and implement a formal project manager knowledge transfer process on decommissioning power reactors.

IV. AGENCY COMMENTS

An exit conference was held with the agency on August 13, 2019. Prior to this meeting, after reviewing a discussion draft, agency management provided comments that have been incorporated into this report, as appropriate. As a result, agency management stated their general agreement with the finding and recommendations in this report and opted not to provide formal comments for inclusion in this report.

Appendix A

OBJECTIVE, SCOPE, AND METHODOLOGY

Objective

To determine whether NRC's transfer of oversight responsibilities, used when operating power reactors undergo decommissioning, is efficient and effective.

Scope

This audit focused on NRC's transition process for decommissioning power reactors. The Office of the Inspector General (OIG) conducted this performance audit from January 2019 to July 2019 at the NRC headquarters (Rockville, MD). Internal controls related to the audit objective were reviewed and analyzed.

Methodology

To accomplish the audit objective, OIG reviewed relevant Federal laws, regulations, and guidance including

- Office Instruction (OI) No.: COM-101, "NRR Interfaces with NMSS."
- NMSS Policy and Procedures 5-1, Revision 3, "Reactor Decommissioning Program Procedures for Interfacing with the Office of Nuclear Reactor Regulation."
- Inspection Manual Chapter 2561, "Decommissioning Power Reactor Inspection Program."
- Title 10, Code of Federal Regulations, Section 50.82, "Termination of license."

- Title 10, Code of Federal Regulations, Section 1.42, "Office of Nuclear Material Safety and Safeguards."
- Title 10, Code of Federal Regulations, Section 1.43, "Office of Nuclear Reactor Regulation."
- Lessons Learned Report, *Power Reactor Transition from Operations to Decommissioning.*

OIG conducted approximately 40 interviews of NRC staff and management to gain an understanding of the roles and responsibilities related to licensees undergoing the decommissioning process and the coordination among offices that have the responsibility of leading the regulatory review and oversight aspects of the decommissioning efforts. Auditors interviewed staff from the Office of Nuclear Reactor Regulation, the Office of Nuclear Material Safety and Safeguards, and the Office of Nuclear Security and Incident Response, as well as the regional offices. OIG also conducted approximately 10 interviews of industry representatives to get their perspectives on the decommissioning process as it relates to the handoff from NRR to NMSS.

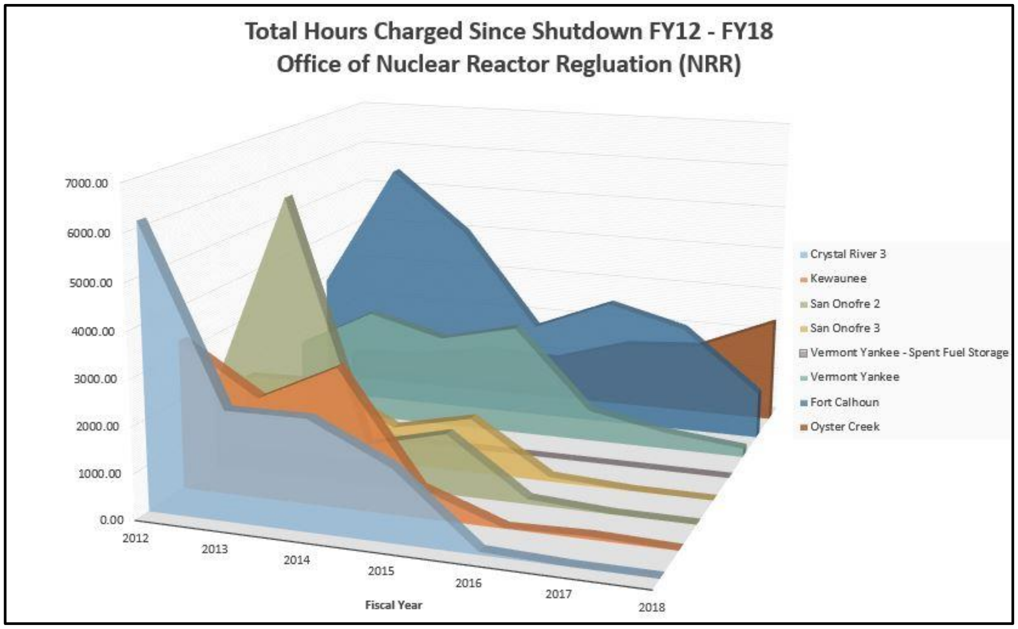
We conducted this performance audit in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our finding and conclusions based on our audit objectives.

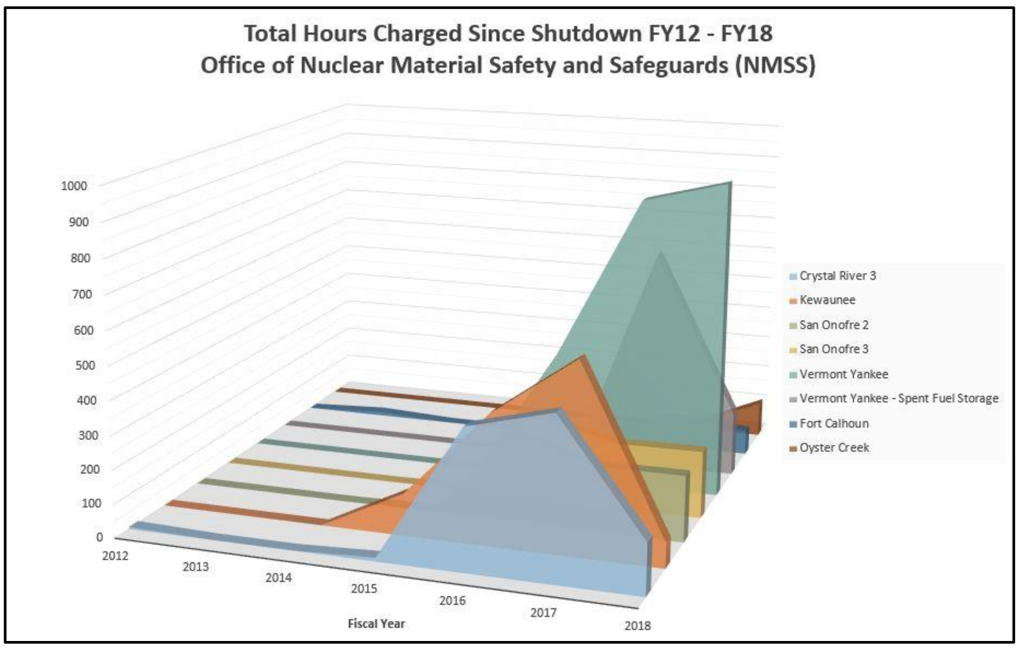
Throughout the audit, auditors considered the possibility of fraud, waste, and abuse in the program.

The audit was conducted by Jacki Storch, Team Leader; Mike Blair, Audit Manager; Roxana Hartsock, Senior Auditor; Janelle Wiggs, Senior Auditor, and Connor McCune, Management Analyst.

Appendix B

Total Hours for Decommissioning Activities Charged Since Shutdown Fiscal Year 2012 – Fiscal Year 2018





Source: OIG generated using agency provided raw data

Appendix C

Nuclear Power Plants with Announced Planned Shutdowns from 2019 to 2025

Plant Name	Planned Shutdown
Three Mile Island Unit 1	September 30, 2019
Indian Point Unit 2	April 30, 2020
Duane Arnold	End of 2020
Indian Point Unit 3	April 30, 2021
Beaver Valley Unit 1	May 31, 2021
Beaver Valley Unit 2	October 31, 2021
Palisades	Spring 2022
Diablo Canyon Unit 1	November 2, 2024
Diablo Canyon Unit 2	August 26, 2025

Source: NRC

TO REPORT FRAUD, WASTE, OR ABUSE

Please Contact:

Email:	Online Form
Telephone:	1-800-233-3497
TTY/TDD:	7-1-1, or 1-800-201-7165
Address:	U.S. Nuclear Regulatory Commission Office of the Inspector General Hotline Program Mail Stop O5-E13 11555 Rockville Pike Rockville, MD 20852

COMMENTS AND SUGGESTIONS

If you wish to provide comments on this report, please email OIG using this link.

In addition, if you have suggestions for future OIG audits, please provide them using this link.

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation

NRR OFFICE INSTRUCTION

Change Notice

Office Instruction No.:	**LIC-107, Revision 2**
Office Instruction Title:	**Procedures for Handling License Transfers**
Effective Date:	**June 5, 2017**
Approved By:	**Michele G. Evans**
Date Approved:	**May 30, 2017**
Primary Contact:	**Tanya E. Hood** **301-415-1387** **Tanya.Hood@nrc.gov** **Richard V. Guzman** **301-415-1030** **Richard.Guzman@nrc.gov**
Responsible Organization:	**NRR/DORL**

Summary of Changes: This issuance of LIC-107, Revision 2, "Procedures for Handling License Transfers," reflects the elimination of the Office of Federal and State Materials and Environmental Management Programs (FSME); additional responsibilities for the Office of Nuclear Material Safety and Safeguards (NMSS); additional guidance on indemnity agreements; additional guidance for the licensing assistants to ensure that conforming amendments are updated in the ADAMS authority file and that any organizational name changes are reflected in the plant's boilerplates, associated NRC Web pages and plant rosters; organizational changes; the availability of updated boilerplates in ADAMS; and miscellaneous editorial changes and clarifications.

Training:	None
ADAMS Accession No.:	**ML17031A006**

Office Instruction: LIC-107, Revision 2, “Procedures for Handling License Transfers”
Dated:

ADAMS Accession No. ML17031A006

OFFICE	NRR/LPL1/PM	NRR/LSPB/LA	NRR/PFPB/BC	NRR/APHB/BC	NMSS/RDB/BC
NAME	DPickett	JBurkhardt	ABowers	SWeerakkody	BWatson
DATE	03 / 07 /2017	02 / 10 / 2017	03 / 16 /2017	03 / 13 /2017	03 / 15 /2017
OFFICE	NMSS/DUWP/D	NRR/LPL1/BC	NRR/DRA/D	NRR/DIRS/D	OGC
NAME	JTappert	JDanna	JGiitter	CMiller	BMizuno
DATE	04 / 06 /2017	03 / 22 /2017	03 / 13 /2017	03 / 31 /2017	04 / 14 /2017
OFFICE	NRR/DORL/DD	NRR/PMDA/D	NRR/DD		
NAME	EBenner	SAbraham	MEvans		
DATE	03 / 28 /2017	05/12 /2017	05/30/2017		

OFFICIAL AGENCY RECORD

NRR OFFICE INSTRUCTION
LIC-107, Revision 2
Procedures for Handling License Transfers

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1. POLICY

The provisions of Section 184 of the Atomic Energy Act of 1954, as amended, and the Nuclear Regulatory Commission's (NRC's) regulations at Title 10 of the *Code of Federal Regulations* (10 CFR) 50.80, "Transfer of licenses," stipulate that NRC approval is required for transfer of control of the ownership and/or operating authority responsibilities within the facility operating license. Specifically, 10 CFR 50.80(a) states, in part, that "No license for a production or utilization facility..., shall be transferred, assigned, or in any manner disposed of, either voluntarily or involuntarily, directly or indirectly, through transfer of control of the license to any person, unless the Commission gives its consent in writing."

An application for transfer of a license is required by 10 CFR 50.80(b) to include as much of the technical and financial qualifications information described in 10 CFR 50.33 and 50.34 on the proposed transferee as would be required for an initial license. After appropriate notice to interested persons (e.g., members of the public), an application for the transfer of a license will be approved, if the Commission determines that: (1) the proposed transferee is qualified to be the holder of the license; and (2) the transfer of the license is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission pursuant thereto. For indirect license transfers that do not involve a change to the licensee, the relevant question with respect to qualifications is whether the indirect transfer of control of the license would affect the qualifications of the existing licensee to continue to hold the license. An approval of the transfer of the license will be accomplished through an order authorizing the transfer and, as necessary, a conforming license amendment will be approved by the order and will be issued when the transfer is consummated.

Other Federal (e.g., Federal Energy Regulatory Commission, Federal Trade Commission, and Department of Justice) and State (e.g., Public Service Commissions) approvals may be required before the proposed transfer can be consummated. These organizations have jurisdiction over issues such as antitrust, rates, and public benefit. The NRC reviews and authorizes, if found acceptable, the proposed transfer within the NRC's jurisdiction. However, the transfer cannot be consummated until the applicant(s) has received regulatory approvals from all governmental agencies with jurisdiction over the transfer.

2. OBJECTIVES

This office instruction describes the processing by the Office of Nuclear Reactor Regulation (NRR) of license transfer applications, including orders and associated conforming amendments. This office instruction also specifies the responsibilities of the NRR licensing project manager (PM) and the technical and financial qualifications reviewers, as well as the interfaces with other offices (e.g., Offices of the General Counsel (OGC) and Nuclear Material Safety and Safeguards (NMSS)) in processing

these licensing actions. This instruction applies to power reactors and research and test reactors.

3. BACKGROUND

License transfer requests can include either "direct" transfers, which are generally those that involve the transfer of ownership or operating authority of the plant itself from one entity to another (e.g., the sale of a plant), or "indirect" transfers, which are generally those that involve the transfer of ownership or control of the licensee itself rather than the facility (e.g., the formation of a new parent holding company above a licensee). License transfer requests can also include partial direct or partial indirect transfers (e.g., the sale of a percentage of a plant or a percentage of a licensee).

The transfer of a license, direct or indirect, normally does not result in any physical changes to the plant or any changes in the conduct of operations. Thus, license transfers do not involve the type of technical issues that would impact plant operation. Typically, the on-site organization and plant staff, including senior managers, will remain essentially unchanged by the license transfer, and plant procedures and policies will not change. Further, the NRC's regulations and the licensee's compliance responsibilities will not change as a result of a license transfer. Therefore, the safety and health of the public is not expected to be adversely affected by the license transfer.

The majority of the staff review of license transfer applications consists of determining whether the ultimately licensed entity meets the financial qualifications, decommissioning funding, foreign ownership, control, or domination, insurance and indemnity, and technical qualifications requirements in the NRC's regulations. The NRC has determined that requests for hearings on applications for license transfers should be governed by a separate subpart of the regulations (Subpart M of 10 CFR Part 2) that provides an efficient and streamlined process for handling hearing requests associated with license transfer applications. The guidance in this office instruction applies to all license transfers conducted under 10 CFR 50.80.

4. BASIC REQUIREMENTS

License transfers are unique in that they result in the exchange of ownership and/or the responsibility for operating a nuclear facility. Typically, the exchange is orchestrated by a team of lawyers representing both the current and future owners and is financially supported by complex agreements that are planned and scheduled for months in advance. It is critical that the PM be aware of the planned transaction date of the license transfer and that the staff's review be supportive of the proposed schedule. Significant financial penalties can be incurred on all parties involved if the staff's review does not support the planned transaction date.

The legal staff of OGC will be involved throughout the processing of the application. Frequent communications between OGC and the legal staffs of the current and/or future owners will occur. Once the application is submitted, the PM should immediately confer with the assigned attorney from OGC to confirm the licensee's characterization of the proposed transaction as being direct versus indirect.

Processing of applications for license transfers is, in many respects, similar to the processing of other licensing actions. Submittals are made to the NRC under oath and affirmation by applicants (current and proposed licensees). If the application is not being made by the current licensee, the applicant should clearly state that the application is being made on behalf of the current licensee, unless there is a hostile acquisition involved, which would be extremely rare and in which case the NRC must give appropriate notice to the current licensee. Staff evaluations are then conducted, and a safety evaluation (SE) is prepared that will accompany the order. In direct transfers, a license amendment will normally be issued upon consummation of the transfer to conform the facility operating license and technical specifications to reflect the new owner and/or operator. The thorough involvement of OGC during the processing of the application from the initial individual *Federal Register* (*FR*) notice to the final order is essential.

5. RESPONSIBILITIES AND AUTHORITIES

Office of General Counsel

The Operating Reactors Division of OGC provides legal advice regarding operating reactors and represents the NRC's staff position in administrative proceedings concerning applications for license amendments. Legal services include, in part, reviewing applications for license transfers, providing advice to the Office of Commission Appellate Adjudication staff regarding license transfer adjudicatory proceedings when the staff is not a party to these proceedings, representing the staff when it is a party to license transfer adjudicatory proceedings, advising the staff on implementation of the Price-Anderson Act, being the point of contact between the NRC and counsel representing licensees and prospective licensees in license transfer applications, and advising the staff throughout the entire license transfer process. Legal services in support of license transfers includes reviewing the initial *FR* notice, reviewing requests for additional information, and reviewing the proposed order, safety evaluation, and conforming amendments.

Director, NRR

Consistent with the delegation of signature authority in NRR Office Instruction ADM-200, “Delegation of Signature Authority,” the Director of NRR signs all orders authorizing the direct transfer of operating licenses and approving the associated conforming amendments for both power reactors and research and test reactors. Although the conforming amendment(s) is not signed and issued until the actual transfer of the ownership of the plant and/or operating authority is consummated, the conforming amendment(s) is approved by the order.

Director, NMSS

If the facility is in SAFSTOR or has been transferred to NMSS in accordance with NRR Office Instruction COM-101, “NRR Interfaces with NMSS,” and a “Transfer of Project Management Responsibilities” memorandum has been signed, NMSS prepares the

order and the Director of NMSS, or designee, signs the order for both direct and indirect license transfers. The Director of NMSS, or designee, also signs the order for any transfer of an independent spent fuel storage installation (ISFSI) that has a specific license as opposed to authorization under the general license provisions of Subpart K to 10 CFR Part 72, "General License for Storage of Spent Fuel at Power Reactor Sites." Finally, the Director of NMSS, or designee, signs the amended ISFSI license if a specific license is involved.

NRR Divisions

The NRR focal points for initial assessment of license transfer requests are the Division of Operating Reactor Licensing (DORL) and the Division of Licensing Projects (DLP). Staff within DORL is responsible for overall management of the review for power reactors whereas DLP is responsible for overall management of the review for research and test reactors.

Director of DORL

Consistent with the delegation of signature authority in ADM-200, the Director of DORL signs all orders approving indirect license transfers for power reactors. In the unusual situation where license amendments are involved with an indirect transfer, the Director of DORL will sign them when issued.

DORL Project Manager

Project manager responsibilities are similar to those for other licensing actions. In addition to the process presented in this office instruction, PMs can find general and other supporting guidance in NRR Office Instruction LIC-101, "License Amendment Review Procedures."

Unlike other licensing actions where OGC does its review and provides "no legal objection" at the conclusion of the review, OGC should be involved from the beginning of the review for license transfers.

The PM will need to be cognizant whether an ISFSI has a specific license or is authorized under the general license provisions of Subpart K to 10 CFR Part 72. Whether an ISFSI is authorized under a specific license or a general license can be readily determined by referring to the appendix to NUREG-1350, "Information Digest," entitled, "Dry Cask Spent Fuel Storage Licensees." Review and approval by NMSS is not required for the transfer of an ISFSI authorized under a general license. However, as discussed further in this office instruction, NMSS approval is required when dealing with an ISFSI authorized under a specific license. The PM will need to coordinate as appropriate with the NMSS counterpart.

DORL Licensing Assistant

Licensing assistant responsibilities are similar to those for other licensing actions. In addition to the process presented in this office instruction, licensing assistants can find general and other supporting guidance in Office Instruction LIC-101.

Division of Licensing Projects

The Director of the Division of Licensing Projects is responsible for financial reviews including decommissioning funding, foreign ownership, control, or domination, insurance and indemnity, reviews of amendments to antitrust license conditions, and for all licensing and oversight for research and test reactors. The Director also signs all orders approving indirect license transfers for research and test reactor licenses, as well as associated license amendments.

Research and Test Reactors Licensing Branch

The Research and Test Reactors Licensing Branch is responsible for overall management of license transfer reviews for research and test reactors. Project management responsibilities for these transfers are similar to those for power reactor license transfers

Financial Projects Branch

The Branch Chief of the Financial Projects Branch (PFPB) is responsible for assigning the review resources and complying with the agreed upon schedule for completion of the financial qualification evaluation as reflected in the NRR Reactor Program System - Licensing/Workload Management (RPS - Licensing/WM) software. The Branch Chief determines whether the target dates and estimate of staff hours required for the review are reasonable. If not, the Branch Chief negotiates new figures with the DORL staff and assigns a PFPB financial analyst to perform the review.

Financial Analyst

The financial analyst will review the financial qualifications, including decommissioning funding, foreign ownership, control, or domination, and insurance and indemnity of the new licensee if a direct transfer is involved or the effect on the current licensee if an indirect transfer is involved, and provide SE input. The financial analyst will work closely with the assigned OGC attorney during the review.

Division of Risk Assessment

The Director of the Division of Risk Assessment is responsible, in part, for providing technical expertise in evaluating licensee technical qualifications.

Operations and Human Factors Branch

The Branch Chief of the Operations and Human Factors Branch is responsible for assigning the review resources and complying with the agreed upon schedule for completion of the technical qualifications evaluation as defined in the RPS - Licensing/WM software. The Branch Chief determines whether the target dates and estimate of staff hours required for the review are reasonable. If not, the Branch Chief negotiates new figures with the DORL staff and assigns a technical qualifications reviewer to perform the review.

Technical Qualifications Reviewer

The technical qualifications reviewer from the Operations and Human Factors Branch will provide an SE input in those transfer cases where the responsibility for the operating authority, plant staffing, technical qualifications, or organizational structure is changed by the transfer.

Other Technical Review Organizations

Branches within the Office of Nuclear Security and Incident Response (NSIR) may provide input on special emergency preparedness or security issues, while NMSS may address spent fuel issues that might be affected by the proposed license transfer. Inputs should be provided to the PM in accordance with the schedule agreed upon in the RPS - Licensing/WM software, so as not to delay issuance of the transfer order.

6. ACTIVITIES IN PROCESSING LICENSE TRANSFER APPLICATIONS

Note: Because the license transfer process is a complex matter governed by many regulations, a companion checklist has been prepared to assist PMs with identifying and addressing all details appropriately. The checklist is included as Enclosure 2 to this office instruction. Project Managers are urged to use the checklist in combination with this office instruction.

The governing parts of the regulations are 10 CFR Part 2, Subpart M (e.g., 2.1301, 2.1315, and 2.1316), 10 CFR Sections 50.33, 50.34, 50.38, 50.40, 50.54(w), 50.80, 50.90 (if an amendment request is involved) and 10 CFR Parts 51 and 140.

Section III.1.e of NUREG-1577, “Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance,” describes the types of transfers that are subject to a 10 CFR 50.80 review. Examples include those involving ownership changes, mergers, formation of holding companies, creation of new unregulated entities which are either subsidiaries of a holding company or stand-alone entities, and other restructuring proposals that go beyond corporate name changes or simple internal reorganizations of functions. If the entity that will become the operating authority (i.e., the operator) is different from the entity that will have ownership of the facility, the financial qualifications for both entities need to be assessed. In this regard, the Commission has stated that, while the same type of financial review done for an

owner is not applicable, there still has to be a financial review for the operator. The operator review is a combination of the financial qualifications of the owner (assuming it is ultimately responsible for costs) with the analysis of the contract between the owner and the operator regarding the payment of costs. The Commission's ruling requiring an appropriate financial qualifications review of a non-owner operator is in the Northern States Power Company/Monticello case, CLI-00-14, 52 NRC 37 (2000), and the companion case, CLI-00-19, 52 NRC 135 (2000).

The NRC consents to license transfers via an order. The order is accompanied by a supporting SE which, in turn, typically has a proprietary and a non-proprietary version due to the discussion of proprietary financial information as part of the financial qualifications analysis. The DORL or DLP administrative staffs and licensing assistants must ensure that the proprietary version of the SE is not dispatched to organizations that have not entered into a non-disclosure agreement with the owner of the information. For indirect license transfers, issuance of the order and SE generally concludes the staff's actions. Direct license transfers typically occur in two separate actions. The first action includes issuance of the order and SE with an unsigned, unnumbered, and undated conforming amendment. The second action includes issuance of the signed, numbered, and dated conforming amendment. As a condition of the license transfer order, the licensee/applicant will inform the staff when all approvals are in place and that the transfer will occur on a specific date. When the specified date arrives and upon notification by the applicant that the transfer will be consummated, the staff will sign and issue the conforming amendment. As its name implies, the conforming amendment does no more than conform the license to reflect the transfer action and is administrative in nature. Typically, a conforming amendment will change the name of the licensee throughout the license so that the license accurately reflects the approved license transfer.

An example of an indirect license transfer is the transfer of the ultimate ownership of the Susquehanna renewed facility operating licenses and general ISFSI license, which is available in Agencywide Documents Access and Management System (ADAMS) under Accession No. ML16320A084. An example of a direct license transfer is the transfer from Entergy to Exelon of the FitzPatrick renewed facility operating license and general ISFSI license. The FitzPatrick order consenting to the license transfer, the supporting SE, and the unsigned, undated, and unnumbered conforming amendment are available in ADAMS under Accession No. ML17041A196. The signed, dated, and numbered conforming amendment for FitzPatrick is available in ADAMS under Accession No. ML17082A283. An example of an amendment to an indemnity agreement is available in ADAMS under Accession No. ML15161A121.

Upon receipt of an application for either a direct or indirect license transfer, the PM, in conjunction with the applicable technical review groups, perform the acceptance review in accordance with NRR Office Instruction LIC-109, "Acceptance Review Procedures," to ensure that the application contains sufficient information as required by 10 CFR 50.80 for the staff to conduct its review. The PM will determine whether the applicant has provided the basis for its schedule request and whether the schedule request is reasonable. If not, the PM and the assigned OGC attorney should contact the applicant and negotiate an appropriate time period for the staff to complete its evaluation. The PM

will need to obtain a specific licensee point of contact and the licensee's schedule for completion of all regulatory reviews in order to coordinate the NRC review schedule. Although license transfer requests are typically filed by licensees, requests may also be filed by a non-licensee (e.g., the intended buyer of the plant), or a co-licensee that is not the operator of the plant (see the Wolf Creek license transfer as an example of two non-operator co-licensees requesting a license transfer despite the opposition of the third non-operator co-licensee, available in ADAMS under Accession No. ML17037D120). In all cases, the NRC products are an order and supporting SE. However, products may include a conforming license amendment and an amendment to the licensee's indemnity agreement. Project managers need to determine which of these products the application supports. License transfer applications can also vary considerably. Occasionally, the staff may not agree with a licensee's determination about the characterization of the request as indirect versus direct. Should the technical and/or legal review staffs determine that an application is incorrectly characterized or does not contain sufficient information to begin the review, the PM will follow the guidance of LIC-109 and work with the assigned OGC attorney.

If the request is for a direct transfer (i.e., one that involves a new licensee and thus requires a conforming change in the name of the owner(s) or operators stated in the license), there should be an accompanying license amendment request pursuant to 10 CFR 50.90. If not, the PM should check with OGC to determine if an amendment is required. The license amendment that conforms the operating license to the new licensees, is referred to as a conforming amendment. Normally, a license amendment is not required for an indirect transfer. However, there are exceptions, particularly if the matter involves an organizationally complex indirect transfer.

The PM may need to coordinate the license transfer review with NMSS. NMSS has responsibility for (1) facilities that are in SAFSTOR, (2) facilities that have been transferred to NMSS in accordance with NRR Office Instruction COM-101, "NRR Interfaces with NMSS," and a "Transfer of Project Management Responsibilities" memorandum has been signed, and (3) ISFSIs that received a specific license. NMSS review and approval is not required for an ISFSI authorized under the general license provisions of Subpart K to 10 CFR Part 72. License transfer reviews may include a permanently shut down facility and almost all license transfer reviews include an ISFSI. The NMSS Office Director, or designee, will need to approve and sign any orders associated with facilities under the responsibility of NMSS. When a license transfer falls under the responsibilities of both NMSS and NRR, the DORL PM typically takes the lead and prepares the SE, order, and conforming amendment. If required, NMSS will prepare the amended license for the ISFSI. The NMSS Office Director, or designee, co-signs the order consenting to the license transfer, signs the applicable conforming amendment(s) and the amended license for the ISFSI if the ISFSI has a specific license.

Most license transfer requests include proprietary financial or commercial information, along with an affidavit requesting that the information be withheld from public disclosure under 10 CFR 2.390. The PM must coordinate (usually with the financial analyst) the review of the information requested to be withheld to determine whether the staff agrees that the information should be withheld. The PM and technical staff should refer to NRR Office Instruction LIC-204, "Handling Requests to Withhold Proprietary Information from

Public Disclosure," for specific guidance. The PM must be aware that the proprietary information may need to be withheld from some of the co-applicants in addition to the general public. The PM must issue a proprietary information determination letter for the proprietary material.

In accordance with the RPS – Licensing/WM software, the PM must request a Cost Activity Code (CAC) for each unit involved. The PM must also confirm that the application is in ADAMS, and that the proprietary and non-proprietary information have been properly profiled.

Working with the NRR Web Services, the PM will request that a non-proprietary copy of the application be placed on the NRC public Web site (a license transfer and merger Web page is available for posting of these documents) in accordance with 10 CFR 2.1301 and 2.1303. The PM should send an e-mail message to NRRWebServices.Resource@nrc.gov and request that information regarding the proposed license transfer be noticed at http://www.nrc.gov/about-nrc/regulatory/adjudicatory/hearing-license-applications.html#change, "Notice of Ownership Change." The PM will need to provide NRR Web Services with the exact information to be included (i.e., 1) Deadline for Filing Hearing Request, 2) Facility and Location, 3) Applicant, 4) Licensing Action, 5) ADAMS Accession Number, and 6) Contact). In addition to the application and any associated requests, the PM will request that NRR Web Services also add to the NRC public Web site Commission correspondence with the applicant related to the application, *FR* notices, the staff's SE, the staff's order acting on the license transfer application and, if a hearing is held, the hearing record and decision. Once the staff has completed all actions associated with the license transfer, the PM should contact NRR Web Services to request that the notice be removed from the NRC's public Web page.

Using the templates for the transmittal letter and the individual *FR* notice (ADAMS Accession Nos. ML082130259 and ML14022A036, respectively) for direct/indirect license transfers (also available in the list of "DORL Master Boilerplates" located on the DORL home page, http://fusion.nrc.gov/nrr/team/dorl/default.aspx), the PM shall process the *FR* notice. The notice must be reviewed and concurred on by OGC. The notice will state that following publication in the *FR*, stakeholders will be permitted to (1) provide comments within 30 days, and (2) request a hearing within 20 days. The PM should be aware that the *FR* notice directs anyone seeking access to the proprietary, confidential information redacted from the publicly available version of the application (typically the proprietary financial projections) to the applicant as opposed to the NRC.

As stated in 10 CFR 2.1315, the Commission has determined that any conforming amendment that only reflects the license transfer action involves no significant hazards consideration. Therefore, such a conforming amendment for a license transfer does not need to be included in the biweekly notice (i.e., BWN) in the *FR.*

The license to be transferred may also reference other licenses that were issued under Parts 30, 40, 70, and/or 72. If that is the case, the PM should coordinate with the offices issuing those licenses so that all transfers are accomplished in parallel and smoothly.

Occasionally, the applicant may request approval of other changes such as a Quality Assurance Plan that must be scheduled to be issued with the transfer order.

The PM shall verify that a copy of the license transfer application was received by the State representative.

The PM needs to be aware of any changes that may need to be made to the indemnity agreement. The Price-Anderson Act (Section 170 of the Atomic Energy Act of 1954, as amended) and the NRC's regulations at 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," and 10 CFR 50.54(w), "Conditions of licenses," require that the plant owner(s) maintain sufficient levels of insurance and that the indemnity agreement reflect the current plant ownership.

Direct license transfers require a change to a licensee's indemnity agreement. The indemnity agreement is updated through PFPB and an advance copy is provided to the PM for licensees to examine for completeness. After the licensees agree to or provide comments on the content of the indemnity agreement, the PM should notify PFPB for further processing. The final copies are forwarded to the PM with signatures from the branch chief of PFPB. Once the order has been issued approving the license transfer, the PM should send out all original signed copies of the indemnity agreement to the licensees for signature. The indemnity agreement(s) should be signed by all licensees concurrently with the issuance of the conforming license amendments upon the consummation of the license transfer action. After the indemnity agreement has all required signatures, one copy should be retained by each licensee for their records and one copy should be sent back to the NRC. A signed copy should be received back to the NRC within 7 days following the consummation of the license transfer action.

Each of the 10 items listed below are distinct sections of the SE for review of a license transfer application. The financial analyst is responsible for producing the content for sections A, B, C, D, and F below. Also, the financial analyst provides input to section J, but not necessarily all of its content. The technical qualifications reviewer is responsible for producing the content for section E while the remaining sections are provided by the PM.

A. Financial Qualifications

B. Decommissioning Funding Assurance

C. Antitrust (special attention must be given if the license contains antitrust conditions; see NUREG-1574, Revision 2)

D. Foreign Ownership, Control, or Domination

E. Technical Qualifications

F. Insurance and Indemnity

G. Conforming Amendment

H. State Consultation

I. Environmental Consideration

J. Conclusion

The financial analyst is responsible for collaboration with the assigned OGC attorney to ensure that all aspects of the financial review are identified, that the scope and content of the evaluation is sufficient, and that any unique financial instruments, license conditions, and indemnity agreement changes are identified. The financial analyst is also responsible for keeping the PM informed and involved in the process. The PM need not be present for every interaction between the financial analyst and OGC. However, the financial analyst needs to keep the PM informed of issues that will require additional information, as well as any significant impact on the overall review schedule.

When preparing an SE, the financial analyst may need to request additional information from the applicant in order to clarify a particular item and complete the review. A request for additional information (RAI) will follow the guidance included in LIC-101. Since requests for license transfers generally involve strict deadlines due to time sensitive financial implications, the financial analyst should attempt to identify any necessary RAIs as soon as possible during the review. Unlike routine RAIs for licensing actions, RAIs associated with license transfers should include OGC review and/or concurrence. The PM should discuss the need for concurrence with OGC before issuing the RAI. Also, since requests for license transfers more often than not contain proprietary information, the resulting staff RAI may also contain proprietary information. Therefore, the PM should discuss the RAI with the applicant before formally issuing the RAI to ensure that any proprietary information is identified and handled appropriately.

The technical qualifications reviewer will review the application using the relevant sections of Chapter 13, “Conduct of Operations,” of NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants,” regarding the conduct of operations to determine whether the plant staffing and management are acceptable to support the technical qualifications of the proposed new operator or the existing operator under the proposed new owner.

License transfers meet the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(21). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment needs to be prepared in connection with the approval of the license transfer or any associated conforming amendments. This finding should be included in the Environmental Consideration section of the SE.

After receipt of SE inputs documenting the results of the technical and financial reviews, the PM prepares the order, the final SE, and the conforming license amendment if required. Templates for the preparation of a direct transfer order, conforming amendment, and SE are available in ADAMS at Accession Nos. ML090500005 and ML090500022. Templates for the preparation of an indirect transfer order and SE are available in ADAMS at Accession Nos. ML090500028 and ML090500026. The SE is

typically prepared in both proprietary and non-proprietary versions. Guidance on the treatment of proprietary information and the NRC's procedures for handling sensitive unclassified non-safeguards information is provided in NRR Office Instruction LIC-204. Any public comments received as a result of the *FR* notice are to be addressed in the SE. Note that it is current practice to have a technical editor review and concur on any document that is to be signed by the NRR Office Director. Thus, the PM may need to forward the draft order to QTE Resource and request that a technical editor review and edit the document. Changes from the tech editor should be incorporated before the document is sent to OGC for concurrence.

The staff's SE will often impose specific conditions on the approval of the license transfer. The PM should ensure that the conditions described in the SE are accurately reflected in the order.

The licensing assistant is responsible for reviewing all license transfer related documents in accordance with the guidance document "DORL Licensing Assistant Review (for Most Documents)" (ADAMS Accession No. ML15352A155), and NRR Office Instruction LIC-101. The licensing assistant will ensure correct usage of noticing templates, and check www.regulations.gov to determine if there were any public comments received. The licensing assistant will review changes to the license if a conforming amendment is involved against the application/supplements and the current license, and assign an amendment number, if needed, for a conforming amendment. In addition, the licensing assistant will perform a final quality and proprietary information check prior to issuance. If the approved license transfer is consummated, the licensing assistant may have additional follow-up activities to ensure that the amended license (if any) is updated in the ADAMS authority file and that any organizational name changes from the conforming amendments are reflected in the plant's boilerplates, and associated NRC Web pages and plant rosters.

> Caution: If the package will be forwarded to the NRR Office Director for signature, it is expected that a second licensing assistant perform a peer review of the package before it is sent to the NRR Office Director. It is recommended that this step be performed after the DORL Division Director review so that all changes made during the concurrence process are reviewed. The DORL PM should request the licensing assistant peer review through their respective branch chief.

If a conforming amendment is issued, the PM will prepare a biweekly notice of issuance of conforming amendments (i.e., BWI) in the *FR* using the DORL template found at ML16166A006.

Typically, there are licensing requests made by the previous license holder that are pending at the time that the conforming amendment is issued. If the new license holder wants the staff to continue work on those licensing requests, the new license holder must submit a letter on the docket on the date of issuance of the conforming amendment or shortly thereafter. The letter must state that the new licensee "adopts and endorses" all outstanding items on the docket, including, but not limited to, requests for license

amendments, exemptions, relief requests, etc. The letter needs to be submitted under oath or affirmation.

The package should have concurrence through the Director, DORL or DLP, before it is sent for final OGC concurrence. Concurrence by OGC will be finalized just prior to the package being presented to the approving official (Office or Division Director, as appropriate). Orders for direct transfers are signed according to the delegation authority of ADM-200. The signature of the NMSS Office Director may be needed if the transfer involves an ISFSI or other NMSS license.

The PM will discuss the need for a communication plan with DORL, DLP, and Regional management. If it is determined that a communication plan is needed, the PM will prepare the plan. The Office of Public Affairs in both headquarters and the Region must be notified at least 3 days before issuance. The Office of Public Affairs may prepare a press release to coincide with release of an order.

If there has been a request for a hearing, it should be addressed in the SE and the order. In the case of a hearing, the Commission will be the "Presiding Officer," unless it designates otherwise. If the Commission remains as the Presiding Officer, the Office of Commission Appellate Adjudication may contact the staff for assistance or information in their role of supporting the Commission as long as the staff does not become a party to the proceeding. If the staff is prepared to issue the order while a hearing request or hearing is pending, the PM must prepare a Notice of Significant Licensing Action (NSLA), prior to issuance of the order, to the Commission and to other NRC offices informing them of the intended issuance of the order approving the license transfer. A copy of the proposed NSLA is included with the package when it is sent to OGC for final concurrence. The NSLA is not made publicly available. Guidance and a template regarding NSLAs are available in an NRR memorandum dated December 13, 2000 (ADAMS Accession No. ML003779315). The NSLA template is also available in ADAMS at Accession No. ML15113A963. [Note: In the rare situation where a hearing request is made subsequent to issuance of the order but prior to issuance of a conforming amendment for a direct license transfer, the PM should use the NSLA template found at ADAMS Accession No. ML15113A797 for the proposed issuance of a conforming amendment.]

The NSLA must be concurred upon by the Director of NRR and the Executive Director for Operations. After the Executive Director for Operations concurs, and at least 5 work days before the proposed issuance of the order, the NSLA should be dated and sent to the Commission. The PM should inform OGC of the transmission of the NSLA to the Commission so that OGC can notify the Presiding Officer and the parties to any proceeding of this communication, as appropriate. After 5 work days, if no communication to the contrary has been received from the Commission, the PM should contact the Office of the Executive Director of Operations to confirm that the Commission does not object to the staff's proposed action. If there is no objection, the order can be issued. The PM should inform OGC of the issuance of the order so that OGC can notify the Presiding Officer and the parties to any proceeding of this action, as appropriate.

7. PERFORMANCE MEASURES

No performance measures for this office instruction have been developed at this time.

8. PRIMARY CONTACTS

Tanya E. Hood	Richard V. Guzman
NRR/DORL/LPL1	NRR/DORL/LPL1
301-415-1387	301-415-1030
Tanya.Hood@nrc.gov	Richard.Guzman@nrc.gov

9. RESPONSIBLE ORGANIZATION

NRR/DORL

10. EFFECTIVE DATE

June 5, 2017

11. REFERENCES

1. *Code of Federal Regulations*, Title 10, Section 50.80, "Transfer of licenses."

2. *Code of Federal Regulations*, Title 10, Section 50.90, "Application for amendment of license, construction permit, or early site permit."

3. NUREG-1577, Revision 1, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance."

4. NUREG-1574, Revision 2, "Standard Review Plan on Transfer and Amendment of Antitrust License Conditions and Antitrust Enforcement."

5. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Chapter 13, "Conduct of Operations," Section 13.1.1, Revision 6, August 2016, and Sections 13.1.2 and 13.1.3, Revision 7, August 2016.

Enclosures:
1. Appendix A - Change History
2. Appendix B – Checklist

Appendix A - Change History

Office Instruction LIC-107, Revision 2
Procedures for Handling License Transfers

LIC-107 Change History			
Revision Date	**Description of Changes**	**Method Used to Announce & Distribute**	**Training**
03/21/2002	This office instruction discusses procedures for handling direct or indirect license transfer requests in accordance with 10 CFR 50.80.	E-mail to NRR staff	None
11/22/2008	Revision to increase level of detail, reflect organizational and editorial changes, and include research and test reactors within the instruction scope.	E-mail to NRR staff	None
05/30/2017	Revision 2 reflects the elimination of the Office of Federal and State Materials and Environmental Management Programs (FSME); additional responsibilities for the Office of Nuclear Material Safety and Safeguards (NMSS); additional guidance on indemnity agreements; additional guidance for the licensing assistants to ensure that the conforming amendment is updated in the ADAMS authority file and that any organizational name changes are reflected in the plant's boilerplates, associated NRC Web pages and plant rosters; organizational changes; the availability of updated boilerplates in ADAMS; and miscellaneous editorial changes and clarifications.	E-mail to NRR staff	None

Appendix B - Checklist

Office Instruction LIC-107, Revision 2
Procedures for Handling License Transfers

This checklist is meant as an aid to PMs in handling license transfer orders and conforming amendments. As such, it is a document that accompanies NRR Office Instruction LIC-107, "Procedures for Handling License Transfers." This checklist does not replace or negate the need to understand the responsibilities and actions required in this office instruction. It should be used in conjunction with the office instruction to assist the PM with planning the work involved in processing and issuing the order, SE, conforming amendment, and other associated documents and to ensure that nothing is inadvertently overlooked. The PM must refer to the details in the office instruction to fully address the scope of actions in the checklist.

FRONT-END ACTIONS OR QUESTIONS

Shortly after receipt of the application from the licensee or applicant, the PM should address the following questions and take appropriate actions:

(1) Does the application meet all pertinent regulatory requirements for submission of an application?

☐ Yes ☐ No

"Any person" may submit an application for license transfer, provided that the application can be supported by "a written consent from the existing licensee, or a certified copy of an order or judgment of a court of competent jurisdiction attesting to the person's right … to possession of the facility or site involved" (10 CFR 50.80). Such an application must be executed in a signed original by a duly authorized officer under oath or affirmation (10 CFR 50.30) and addressed to the NRC Document Control Desk (10 CFR 50.4). For additional guidance regarding oath or affirmation, and an alternate method to meet this requirement, see Regulatory Issue Summary 2001-18 (ADAMS Accession No. ML010990211). The PM should discuss with the licensee remedial actions if any of these requirements are not met.

(2) Is the transfer direct or indirect? ☐ Direct ☐ Indirect

Did the application request a conforming amendment? ☐ Yes ☐ No

A direct transfer involves a new licensee, and most likely would need a name change in the license (i.e., the application should include an application for a conforming amendment to reflect the new licensee name). On the other hand, an indirect transfer may involve a change in the parent or holding company of the current licensee, and may not need anything changed in the current operating license. If in doubt, consult with OGC and discuss with the licensee.

In terms of work planning, a separate CAC number may be needed for the conforming amendment if the target date for consummation of the transfer is significantly later than that for the order.

Enclosure 2

(3) Does the application include “as much of the information described in §§ 50.33 and 50.34 of this part with respect to the identity and technical and financial qualifications of the proposed transferee as would be required by those sections if the application were for an initial license”?

☐ Yes ☐ No

At this early stage of review, the PM should discuss the acceptance review for sufficiency of information to begin the review with the responsible technical branches. The PM should refer to NRR Office Instruction LIC-109, “Acceptance Review Procedures,” for guidance. The PM should promptly communicate with the licensee if any deficiency is identified.

(4) Is a copy of the publicly available version of the application placed on the NRC public Web site? ☐ Yes ☐ No

This requirement is stated in 10 CFR 2.1301. Per 10 CFR 2.1303, unless exempt from disclosure under 10 CFR Part 9, the following documents should also be placed on the NRC public Web site: (a) correspondence to and from the applicant or licensee related to the application, (b) *FR* notices, (c) NRC staff safety evaluations, (d) NRC staff order, and (e) if a hearing is held, hearing records and decision.

(5) If the plant site houses an independent spent fuel storage installation (ISFSI) with a specific license, did the application also address transfer of the ISFSI?

☐ Yes ☐ No

The PM needs to discuss this with NMSS to understand its scope of review as it relates to NRR’s review, and agree on target dates. If the application makes no mention of the ISFSI with a specific license, the PM should immediately discuss with the licensee and NMSS about the omission.

(6) Has OGC been informed of the application and provided copies? ☐ Yes ☐ No

License transfer reviews are mostly concerned with legal and financial matters. Accordingly, OGC should be involved from the start of the acceptance review. The assigned OGC attorney normally keeps in touch with attorneys representing the applicant and/or the licensee, the NRR financial reviewer(s), and the PM during the review. Note that OGC must concur on all correspondence from the staff including *FR* notices and may also need to concur on requests for additional information, particularly when a hearing has been requested.

(7) Is public notification prepared and issued? ☐ Yes ☐ No

The regulations at 10 CFR 50.80 requires the NRC staff to issue an “appropriate notice to interested persons, including the existing licensee.” This notice is to be published in the *FR* (see template at ADAMS Accession No. ML14022A036). The notice will (1) describe the proposed transfer; (2) announce that requests for a hearing must be filed within 20 days; (3) announce that written comments must be filed within 30 days per

10 CFR 2.1305, (4) declare that, per 10 CFR 2.1315, and unless otherwise determined by the Commission, the conforming amendment to be issued involves no significant hazards consideration (NSHC) and no comments on the NSHC determination are solicited from the public; and (5) state that the comment procedures contained in 10 CFR 2.1305 apply. The PM should make sure that the *FR* notice directs anyone seeking access to the proprietary, confidential information redacted from the publicly available version of the application (typically the proprietary financial projections) to the applicant as opposed to the NRC.

If the applicant determined that a conforming amendment is needed, it would apply for it under 10 CFR 50.90. Under such circumstance, 10 CFR 50.91 requires the applicant to provide an NSHC analysis. The NRC staff, however, does not need to publish an NSHC evaluation because 10 CFR 2.1315 has generically determined that a conforming amendment involves NSHC; this is so stated in the NRC staff's *FR* notice regarding the proposed license transfer.

Per 10 CFR 2.309(b)(1), the *FR* notice will specify a date, 20 days from publication, on or before which hearing requests and intervention petitions must be filed.

(8) Does the application propose an issuance date for the order and conforming amendment?

☐ Yes ☐ No

Some applications are very specific in this regard, while others only provide a general target date because the applicant/licensee may still be undergoing financial negotiations and seeking approval from other governmental bodies. License transfers typically involve significant time-sensitive financial implications (e.g., the fuel in a reactor core is worth tens of thousands of dollars less after each day of burnup). The NRC staff's failure to approve the transfer on the date the application specifies could mean significant financial penalty, or significant re-work of the financial arrangements. Thus, it is incumbent upon the PM to ensure that the NRR technical review branches, NMSS, and OGC all aim their review schedule using the same target date.

(9) What should be done about environmental considerations?

There is no statutory or regulatory requirement for an environmental impact statement or environmental assessment for the order and conforming amendment. The regulation at 10 CFR 51.22(c)(21) provides that approvals of direct or indirect license transfers and any associated conforming amendments are categorically excluded from environmental review. The "Environmental Considerations" section of the SE should cite this regulation.

(10) Does the application indicate that a copy has been sent to the designated State official?

☐ Yes ☐ No

This requirement is specified in 10 CFR 50.91(b)(1) regarding amendments. Specifically, the licensee should have sent a copy of the application to the designated State official.

(11) Does the application contain proprietary information? ☐ Yes ☐ No

License transfer applications usually contain proprietary information. The NRC staff should follow the guidance of NRR Office Instruction LIC-204. In the context of a proposed license transfer order and conforming amendment, the staff needs to be cautious in its day-to-day activities (e.g., issuance of formal or draft correspondence) such that proprietary information is not inadvertently released. The PM should be cognizant that one party in the transaction may be withholding certain information from another party. This is typical for financial projections when each entity is in competition in the same power market area. Note that proprietary information may be as simple as a number (e.g., dollar amounts), a word, or a single phrase. Inadvertent release of proprietary information is reportable to the Inspector General and the Executive Director for Operations (see Management Directive 3.4, section on “Inadvertent Release of Information”).

WORK PLANNING

License transfers typically involve significant time-sensitive financial implications (e.g., the fuel in a reactor core is worth tens of thousands dollars less after each day of burnup). The NRC staff’s failure to approve the transfer on the date the application specifies could mean significant financial penalty, or significant re-work of the financial arrangements.

(1) Through RPS - Licensing/WM software, assign PFPB to complete the financial qualifications review. PFPB reviews the financial qualifications of the proposed owner and operator (if different from the owner).

If the entity that will become the operator is different from the entity that will become the owner, the financial qualification for both entities needs to be assessed. While the exact same type of financial review done for an owner is not applicable for the operator, PFPB still needs to review a combination of the financial qualifications of the owner (assuming it is ultimately responsible for costs) with the analysis of the contract between the owner and the operator regarding the payment of costs. See the Commission ruling on the Northern States Power Company/Monticello case, CLI-00-14, 52 NRC 37 (2000), and the companion case, CLI-00-19, 52 NRC 135 (2000).

☐ Yes ☐ No

(2) Through RPS - Licensing/WM software, assign the Operations and Human Factors Branch to complete the technical qualifications review.

☐ Yes ☐ No

(3) Does the plant site include an ISFSI, under a specific or general license, which would be transferred at the same time?

☐ Yes ☐ No

If the ISFSI received a specific license as opposed to authorization under the general license provisions of Subpart K to 10 CFR Part 72, the NMSS Office Director, or

designee, must sign the order consenting to the license transfer and the amended ISFSI license. The DORL PM should also confirm that NMSS will revise the ISFSI license as appropriate.

(4) Are the SE target dates supportive of the proposed date of consummation of the transfer?

☐ Yes ☐ No

PRE-ISSUANCE OBLIGATIONS FOR THE ORDER

(1) Has the 20-day period (i.e., the period for requesting a hearing) required by 10 CFR 2.309(b)(1) passed since publication of the notice in the *FR*? ☐ Yes ☐ No

(2) Any comments from the public or State government? ☐ Yes ☐ No

Per 10 CFR 2.1305, as an alternative to requests for hearings and petition to intervene, persons may submit written comments regarding license transfer applications. The NRC will consider and, if appropriate, respond to these comments, but these comments do not otherwise constitute part of the decisional record.

(3) Are all of the applicant's submittals (i.e., original application and any supplemental information) submitted under oath or affirmation, and docketed in ADAMS?

☐ Yes ☐ No

(4) Has the PM issued a letter to determine withholding from public disclosure for each applicant submittal containing proprietary information?

☐ Yes ☐ No

The applicant's submittals typically contain proprietary information of financial nature (i.e., dollar amounts). The PM should suspect that any formal or informal communication with the applicant may likewise contain proprietary information, and handle them accordingly.

(5) If a hearing has been requested and the hearing will not be completed before issuance of the order, did the PM prepare an NSLA to inform the Commission of the imminent issuance of the order?

☐ Yes ☐ No

If there is an ongoing or pending hearing, it should be so noted in the SE and the order. Before issuance of the order, the PM prepares an NSLA to inform the Commission of the imminent issuance of the order. The PM should inform OGC when the NSLA is transmitted to the Commission.

(6) Did the PM discuss with management and the Regional office about the need for a communication plan?

☐ Yes ☐ No

There is no regulatory requirement or guidance that specifies a communication plan. The need for such would be determined by the level of public interest in the proposed license transfer or the plant itself (e.g., requests for intervention, public comments, State government comments, media interest, etc.).

(7) Did the proposed new licensee provide a letter to the NRC stating that it has the required insurance?

☐ Yes ☐ No

This letter is needed before PFPB can issue an amendment to the indemnity agreement to reflect the name of the new licensee.

(8) Has PFPB prepared an amended or new indemnity agreement?

☐ Yes ☐ No

An indemnity agreement is required to reflect the ownership of the facility. Therefore, a direct license transfer typically requires an amended or new indemnity agreement that is issued concurrent with the conforming amendment(s) upon the consummation of the license transfer action. The indemnity agreement for an indirect license transfer is generally unchanged.

(9) Did the licensee/applicant send a letter to the NRC to indicate the date the transaction will be consummated?

☐ Yes ☐ No

The conforming amendment is to be issued on that day, not before and not after.

(10) Did the new licensee send a letter to the NRC to identify all the ongoing reviews (amendments, exemptions, relief requests, etc.), and request the NRC to continue its review of those actions?

☐ Yes ☐ No

This letter is needed because those actions were requested by the prior licensee, and the NRC has no reason to continue its review unless the new licensee “adopts and endorses” the outstanding items on the docket. Since some of the ongoing reviews (e.g., amendments) were requested by the prior licensee under oath or affirmation, the new licensee’s “adoption” letter must also be under oath or affirmation, or equivalent.

PREPARATION OF CONFORMING AMENDMENT

Issuing the conforming amendment is essentially done the same way as issuing a regular amendment, except that the package contains no SE because the conforming amendment is referenced and approved as part of the order consenting to the license transfer. In addition, the

amendment package contains a biweekly notice of issuance of conforming amendments (template at ADAMS Accession No. ML16166A006).

The conforming amendment, the amended or new indemnity agreement, the amended ISFSI license, if applicable, and biweekly notice of issuance are issued on the day the license transfer transaction is consummated and after receipt of notification from the licensee confirming the transaction. This is necessary because if it is issued before, the new licensee name may invalidate the operating license for the current and exiting licensee, and if it is issued afterwards, the new licensee would have no authorization to operate under the old license.

(1) Does the conforming amendment package include an amendment to the indemnity agreement (prepared by PFPB) for the new licensee?

☐ Yes ☐ No

(2) Did the PM inform the NRR Director, who is the signer of the conforming amendment, that the conforming amendment is identical to the draft issued with the order, or that minor changes had been made?

☐ Yes ☐ No

NRR-DMPSPEm Resource

From:	Wall, Scott
Sent:	Thursday, March 21, 2019 3:14 PM
To:	Couture III, Philip
Cc:	Byrne, Robert M ; Powers, Michael J; Miner, Peter; Halter, Mandy
Subject:	RAI - Pilgrim - Application for Order Consenting to Direct and Indirect Transfers of Control of Licenses and Approving Conforming License Amendment (EPID: L-2018-LL0-0003)

Mr. Couture:

By letter dated November 16, 2018 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML 18320A031), as supplemented by letter dated November 16, 2018 (ADAMS Accession ML18320A040), Entergy Nuclear Operations, Inc. (ENOI), on behalf of itself and Entergy Nuclear Generation Company (ENGC) (to be known as Holtec Pilgrim, LLC), Holtec International (Holtec), and Holtec Decommissioning International, LLC (HDI) (together, "Applicants"), requested that the U.S. Nuclear Regulatory Commission (NRC) consent to: (1) the indirect transfer of control of the Renewed Facility Operating License No. DPR-35 for the Pilgrim Nuclear Power Station (Pilgrim), as well as the general license for the Pilgrim Independent Spent Fuel Storage Installation (ISFSI) (collectively the "Licenses"), to Holtec; and (2) the direct transfer of ENOI's operating authority (i.e., its authority to conduct licensed activities at Pilgrim) to HDI. In addition, the Applicants requested that the NRC approve a conforming administrative amendment to the Licenses to reflect the proposed direct transfer of the Licenses from ENOI to HDI; a planned name change for ENGC from ENGC to Holtec Pilgrim, LLC; and deletion of certain license conditions to reflect satisfaction and termination of all ENGC obligations after the license transfer and equity sale. In addition, HDI submitted an exemption request, as an enclosure to the letter dated November 16, 2018, to allow HDI to use of a portion of the nuclear decommissioning trust for spent fuel management and site restoration costs.

Based on the NRC staff's initial review of the license transfer request, the following request for additional information (RAI) is required to facilitate completion of the staff's technical review.

The enclosure to this email provides the RAI. On March 6, 2019, the draft RAI question was sent to you to ensure that they were understandable, the regulatory bases for the question were clear, and to determine if the information was previously docketed. On March 18, 2019, a clarifying teleconference was held at which time Entergy agreed to respond to the RAI within 30 days of the date of this email.

If you have any questions, please contact me at 301-415-2855 or via e-mail at Scott.Wall@nrc.gov.

Scott P. Wall, LSS BB, BSP
Senior Project Manager
Special Projects and Process Branch
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation
301.415.2855
Scott.Wall@nrc.gov

Docket No. 50-293

Enclosure:
Request for Additional Information

RAI-IRAB-1

REQUEST FOR ADDITIONAL INFORMATION

LICENSE TRANSFER REQUEST

ENTERGY NUCLEAR OPERATIONS, INC.

PILGRIM NUCLEAR POWER STATION

Background

By letter dated November 16, 2018 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML 18320A031), as supplemented by letter dated November 16, 2018 (ADAMS Accession ML18320A040), Entergy Nuclear Operations, Inc. (ENOI), on behalf of itself and Entergy Nuclear Generation Company (ENGC) (to be known as Holtec Pilgrim, LLC), Holtec International (Holtec), and Holtec Decommissioning International, LLC (HDI) (together, "Applicants"), requested that the U.S. Nuclear Regulatory Commission (NRC) consent to: (1) the indirect transfer of control of the Renewed Facility Operating License No. DPR-35 for the Pilgrim Nuclear Power Station (Pilgrim), as well as the general license for the Pilgrim Independent Spent Fuel Storage Installation (ISFSI) (collectively the "Licenses"), to Holtec; and (2) the direct transfer of ENOI's operating authority (i.e., its authority to conduct licensed activities at Pilgrim) to HDI. In addition, the Applicants requested that the NRC approve a conforming administrative amendment to the Licenses to reflect the proposed direct transfer of the Licenses from ENOI to HDI; a planned name change for ENGC from ENGC to Holtec Pilgrim, LLC; and deletion of certain license conditions to reflect satisfaction and termination of all ENGC obligations after the license transfer and equity sale. In addition, HDI submitted an exemption request, as an enclosure to the letter dated November 16, 2018, to allow HDI to use of a portion of the nuclear decommissioning trust for spent fuel management and site restoration costs.

Applicable Regulation and Guidance

Title 10 of the *Code of Federal Regulations* (10 CFR), Section 50.80(b) states, in part: (1) An application for transfer of a license shall include: (i) For a construction permit or operating license under this part, as much of the information described in §§50.33 and 50.34 of this part with respect to the identity and technical and financial qualifications of the proposed transferee as would be required by those sections if the application were for an initial license."

Section 50.80(c) of 10 CFR states, in part: "…the Commission will approve an application for the transfer of a license, if the Commission determines: (1) That the proposed transferee is qualified to be the holder of the license; and (2) That transfer of the license is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission pursuant thereto."

Section 10 CFR 50.40 of 10 CFR states, in part: "In determining that a construction permit or operating license in this part […] will be issued to an applicant, the Commission will be guided by the following considerations: […] (b) The applicant for construction permit, operating license, […] is technically and financially qualified to engage in the proposed activities in accordance with the regulations in this chapter."

NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition," Chapter 13, "Conduct of Operations," Section 13.1.1, "Management and Technical Support Organization," Revision 6, Section I, "Areas of Review," states, in part: "The objective of this review is to ensure that the corporate management is involved with, informed of, and dedicated to the safe […] operation of the nuclear plant. In addition, the review is to ensure that sufficient resources have been, are being, and will continue to be provided to adequately accomplish these objectives."

Issue

By letter dated November 16, 2018 (Agencywide Documents Access and Management System (ADAMS) Accession Number ML18320A165), Entergy Nuclear Generation Company, Inc. (“ENOI”), on behalf of itself and Entergy Nuclear Generation Company (“ENGC”), Holtec International (“Holtec”), and Holtec Decommissioning International, LLC (“HDI”) submitted an application for order approving the indirect transfer of control of the operating license for the Pilgrim Nuclear Power Station (“Pilgrim”) to Holtec, and the direct transfer of ENOI’s operating authority to HDI, to the U.S. Nuclear Regulatory Commission (NRC) for approval. Attachment 1 to the abovementioned letter, Section 1, “Introduction,” states, in part, that “HDI was formed by Holtec to operate and decommission all Holtec-owned decommissioning nuclear power plant sites, including Pilgrim. HDI’s mission is to assume licensed operator responsibilities for decommissioning nuclear power plants that Holtec acquires including Pilgrim.”

By letter dated August 31, 2018 (ADAMS Accession Number ML18243A488), Exelon Generation Company, LLC (“Exelon Generation”), Oyster Creek Environmental Protection (“OCEP”), LLC, and HDI, submitted an application for order approving direct transfer of the operating license for Oyster Creek Nuclear Generating Station from Exelon Generation to OCEP as the licensed owner and to HDI as the licensed operator, for NRC’s approval. The application stated that HDI, as licensed operator, will provide the overall management of decommissioning activities at Oyster Creek.

<u>RAI-IRAB-1</u>

Should both license transfers be approved, HDI will be responsible for conducting licensed activities at two sites simultaneously (Pilgrim and Oyster Creek), including possession and disposition of radioactive material, maintenance of the facilities in a safe condition (including storage, control, and maintenance of the spent fuel), decommissioning and decontamination of the facilities, and maintenance of the Independent Spent Fuel Storage Installations until they can be decommissioned. Provide additional information that justifies that HDI’s management and technical support organization will have sufficient resources (i.e. corporate structure, management and technical support organization staff capacities, internal procedures, etc.) to conduct licensed activities at multiple sites.

Hearing Identifier: NRR_DMPS
Email Number: 887

Mail Envelope Properties (BN6PR09MB14272DC113A1B497082045F392420)

Subject: RAI - Pilgrim - Application for Order Consenting to Direct and Indirect Transfers of Control of Licenses and Approving Conforming License Amendment (EPID: L-2018-LL0-0003)
Sent Date: 3/21/2019 3:13:45 PM
Received Date: 3/21/2019 3:13:00 PM
From: Wall, Scott

Created By: Scott.Wall@nrc.gov

Recipients:
"Byrne, Robert M " <rbyrne@entergy.com>
Tracking Status: None
"Powers, Michael J" <mpower1@entergy.com>
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Tracking Status: None

Post Office: BN6PR09MB1427.namprd09.prod.outlook.com

Files	**Size**	**Date & Time**
MESSAGE	8835	3/21/2019 3:13:00 PM

Options
Priority: Standard
Return Notification: No
Reply Requested: No
Sensitivity: Normal
Expiration Date:
Recipients Received:

HOLTEC
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April 17, 2019

10 CFR 50.80(b) and (c)
10 CFR 50.34

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Pilgrim Nuclear Power Station
Renewed Facility Operating License No. DPR-35
NRC Docket Nos. 50-293 and 72-1044

Subject: Response to NRC Request for Additional Information

References:

[1] Letter from A. Christopher Bakken III, (Entergy Nuclear Operations, Inc) to U.S. Nuclear Regulatory Commission - Application for Order Consenting to Direct and Indirect Transfers of Control of Licenses and Approving Conforming License Amendment; and Request for Exemption from 10 CFR 50.82(a)(8)(i)(A) for Pilgrim Nuclear Power Station, dated November 16, 2018 (ADAMS Accession No. ML18320A031).

[2] Letter from Pamela B. Cowan, (Holtec Decommissioning International) to U.S. Nuclear Regulatory Commission – Notification of Revised Post Shutdown Decommissioning Activities Report and Revised Site-Specific Decommissioning Cost Estimate for Pilgrim Nuclear Power Station, dated November 16, 2018 (ADAMS Accession No. ML18320A040).

[3] Email from Scott P. Wall, (U.S. Nuclear Regulatory Commission) to Philip Couture (Entergy Nuclear Operations, Inc)—RAI-IRAB-1—Pilgrim—Application for Order Consenting to Direct and Indirect Transfers of Control of Licenses and Approving Conforming License Amendment, dated March 21, 2019 (ADAMS Accession No. ML19086A349).

Please find attached the “Response to NRC Request for Additional Information (RAI) Regarding the Request for Direct and Indirect Pilgrim License Transfers, RAI-IRAB-1” prepared and submitted herein by Holtec Decommissioning International, LLC (HDI).

By letter dated November 16, 2018 (Reference 1), as supplemented by letter dated November 16, 2018 (Reference 2), Entergy Nuclear Operations, Inc. (ENOI), on behalf of itself and Entergy Nuclear Generation Company (ENGC) (to be known as Holtec Pilgrim, LLC), Holtec International (Holtec), and Holtec Decommissioning International, LLC (HDI) (together, "Applicants"), requested that the U.S. Nuclear Regulatory Commission (NRC) consent to: (1) the indirect transfer of control of the Renewed Facility Operating License No. DPR-35 for the Pilgrim Nuclear Power Station (Pilgrim), as well as the general license for the Pilgrim Independent Spent Fuel Storage Installation (ISFSI) (collectively the "Licenses"), to Holtec; and (2) the direct transfer of ENOI's operating authority (i.e., its authority to

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conduct licensed activities at Pilgrim) to HDI. In addition, the Applicants requested that the NRC approve a conforming administrative amendment to the Licenses to reflect the proposed direct transfer of the Licenses from ENOI to HDI; a planned name change for ENGC from ENGC to Holtec Pilgrim, LLC; and deletion of certain license conditions to reflect satisfaction and termination of all ENGC obligations after the license transfer and equity sale. In addition, HDI submitted an exemption request, as an enclosure to the letter dated November 16, 2018, to allow HDI to use a portion of the nuclear decommissioning trust for spent fuel management and site restoration costs.

In Reference 3, The NRC provided ENOI with a request for additional information. The HDI response to this RAI is provided in the Enclosure to this letter.

This letter contains no new regulatory commitments.

In the event that the NRC has any questions about the transactions described in this letter or needs to obtain any additional information, please contact the undersigned at 724-493-1833 or a.sterdis@holtec.com.

I declare under penalty of perjury that the foregoing is true and correct. Executed on April 17, 2019.

Respectfully,

Andrea L. Sterdis

Andrea L. Sterdis
Vice President Regulatory and Environmental Affairs
Holtec Decommissioning International, LLC

Enclosure: Response to NRC Request for Additional Information (RAI) Regarding the Request for Direct and Indirect Pilgrim License Transfers, RAI-IRAB-1

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cc (w/Enclosure):

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NRC Senior Resident Inspector
Pilgrim Nuclear Power Station

Enclosure

Pilgrim Nuclear Power Station

HDI Response to U.S. NRC Request for Additional Information (RAI) Regarding the Request for Direct and Indirect Pilgrim License Transfers

RAI-IRAB-1

RAI-IRAB-1

Provide additional information that justifies that HDI's management and technical support organization will have enough resources (i.e. corporate structure, management and technical support organization staff capacities, internal procedures, etc.) to conduct licensed activities at multiple sites.

HDI Response to RAI-IRAB-1

To ensure that HDI's management and technical support organization will have sufficient resources (i.e. corporate structure, management and technical support organization staff capacities, internal procedures, etc.) to conduct licensed activities at multiple sites, HDI will be using a fleet model to manage and conduct the decommissioning of its shutdown nuclear power plants. In particular, the HDI decommissioning fleet corporate organization infrastructure is based on a Governance, Oversight, Support and Performance (GOSP) management model, and each of the model principles are discussed in further detail below. In summary, this fleet model provides for efficiency by establishing standard processes, procedures, and approaches at the corporate level and at the decommissioning sites, similar to the model used by many operating plant fleets. In addition, each of HDI's decommissioning sites will have dedicated leadership reporting to the same HDI corporate executive team and sufficient technical support from the CDI site organizations mainly made up of experienced incumbents and supplemented as needed by additional Holtec and SNC-Lavalin resources. Note also that the scope of HDI's licensed responsibilities at each site, while just as important, will be much smaller in scope than at an operating site and will primarily be maintaining the facility in a safe condition (including the storage, control and maintenance of the spent nuclear fuel), possessing and disposing of radioactive material, decommissioning and decontaminating the site, and maintaining the Independent Spent Fuel Storage Installation (ISFSI) until the spent nuclear fuel is removed from the site and the ISFSI can be decommissioned.

Governance

HDI will implement governance procedures at both the HDI corporate level and at the site level. At the corporate level, for example, HDI will implement a procedure related to control of trust fund withdrawals that will apply at all sites for which it is the licensed operator, to ensure consistency and increase efficiencies. At the site level, HDI plans on initially adopting the former licensee's applicable existing policies, programs, and procedures, with minimal to no revisions or substitutions, which will ensure a seamless transition after license transfer. As decommissioning progresses at the sites, HDI intends to make changes to the site governance documents in accordance with NRC regulations, with the overall goal of standardizing site governance documents across the HDI fleet as much as practicable. This approach allows efficiency in oversight and the application of site-specific lessons-learned and operating experience to the other sites in the HDI fleet.

Oversight

The executive leadership team at the HDI corporate level will oversee the safety, operation, and decommissioning at the Oyster Creek and Pilgrim sites. The corporate executive leadership team consists of the HDI Vice President of Licensing; Treasurer & NDT Management; Vice President of Technical Support; Senior Vice President and Chief Operating Officer; Vice President of Quality Assurance and

Nuclear Oversight; President and Chief Nuclear Officer; and the Holtec Executive Committee (see organization charts provided at page 8 of Oyster Creek LTA and page 7 of Pilgrim LTA). The HDI Site Vice President at each site will further support the corporate executive team's oversight over HDI's sites. HDI will hold meetings with the HDI Site Vice Presidents and the HDI corporate executive leadership team to share experience for efficiency and support in implementation and improvement. The corporate HDI and CDI executive team is structured and staffed in anticipation of supporting multiple sites' planning and decommissioning activities, with the capacity to expand as needed, as HDI continues to expand its nuclear decommissioning business.

Support

The onsite organizations will include incumbent plant staff who will be retained at license transfer. Additional support during multiple decommissioning projects will be provided by the CDI corporate organization, which because of its affiliation with both SNC-Lavalin and Holtec International, its large corporate parents, has easy access to technical and project resources as needed if issues arise. As the Applications indicate, SNC-Lavalin has a workforce of over 50,000, and through its subsidiary, Atkins, has substantial decommissioning expertise and experience, while Holtec International is an industry leader in spent fuel management.

Performance

The performance, or implementation, function for the GOSP model at each site will primarily be achieved through CDI, although the CDI staff at each site performing most of the regulatory required functions following license transfer will have been retained from the current licensee. Specifically, HDI is working with CDI to retain the incumbent personnel, with special emphasis on the senior leadership and plant operating experts, in place at each nuclear plant at the time of license transfer. These incumbent plant experts who are and have been responsible for conducting the activities to maintain the plant in a safe and compliant condition, will bring vast amounts of site history, knowledge and experience to the team. These incumbent nuclear professionals are experienced in owning, maintaining and executing the existing policies, programs and procedures. These incumbent senior leadership and plant operating experts, along with additional existing plant staff that are retained in the organization at License Transfer, will be supplemented by experts in decommissioning and dismantlement to fully round out successful and experienced teams at each site.

As reflected in Figure A-1 of the Pilgrim Application, each site will initially have its own HDI Site Vice President. In addition, separate management teams that will be employed by CDI but under HDI's direction and control, will report to the Site Vice President. These include separate Decommissioning General Managers, as well as separate managers for the various functional areas. The establishment of separate management teams for each site will allow appropriate, direct, supervision of the decommissioning activities at each site.

In addition, to ensure uninterrupted plant operation and decommissioning of the sites at license transfer, HDI is currently working with the existing site and corporate functional area managers at both Exelon and Entergy to identify the applicable corporate and site policies, programs and procedures to be adopted by HDI upon license transfer.

NRR-DRMAPEm Resource

From: Lamb, John
Sent: Monday, June 3, 2019 7:15 AM
To: Miner, Peter
Cc: Byrne, Robert M; Powers, Michael J; Halter, Mandy; Couture III, Philip
Subject: RAI - Pilgrim Post-Decommissioning Technical Specifications (PDTS) License Amendment Request (LAR) (EPID: L-2018-LLA-0268)

Importance: High

Mr. Miner:

By letter dated September 13, 2018 (Agencywide Documents Access and Management System (ADAMS) No. ML18260A085), as supplemented by letters dated January 10, February 8, and March 14, 2019 (ADAMS Nos. ML19016A135, ML19044A574, and ML19079A158), Entergy Nuclear Operations, Inc. (Entergy, the licensee) submitted a license amendment request (LAR) to revise Pilgrim Nuclear Power Station (Pilgrim) Renewed Facility Operating License and associated Technical Specifications (TS) to Permanently Defueled Technical Specifications (PDTS) consistent with the permanent cessation of reactor operation and permanent defueling of the reactor.

The U.S. Nuclear Regulatory Commission (NRC) staff has reviewed the information provided in the LAR and determined that additional information is required in order to complete its review. The request for additional information (RAI) is included below. The NRC staff held a clarifying call with Entergy on May 28, 2019, to ensure the RAIs were understandable. Entergy will respond to the RAIs within 45 days from the date of this email.

Sincerely,

John G. Lamb

Docket Nos.: 50-293

REQUEST FOR ADDITIONAL INFORMATION (RAI)

NRR-SNPB-01

By letter dated September 13, 2018 (Agencywide Documents Access and Management System (ADAMS) No. ML18260A085), as supplemented by letters dated January 10, February 8, and March 14, 2019 (ADAMS Nos. ML19016A135, ML19044A574, and ML19079A158), Entergy Nuclear Operations, Inc. (Entergy, the licensee) submitted a license amendment request to revise Pilgrim Nuclear Power Station (Pilgrim) Renewed Facility Operating License and associated Technical Specifications (TS) to Permanently Defueled Technical Specifications (PDTS) consistent with the permanent cessation of reactor operation and permanent defueling of the reactor.

Applicable Regulation and Guidance

The requirements of Title 10 of the Code of Federal Regulations (10 CFR) Part 50.36(a)(6), *Decommissioning*, states:

> This paragraph applies only to nuclear power reactor facilities that have submitted the certifications required by § 50.82(a)(1) and to non-power reactor facilities which are not authorized to operate. Technical Specifications involving safety limits, limiting safety system settings, and limiting control system settings; limiting conditions for operation; surveillance requirements; design features; and administrative controls will be developed on a case-by-case basis.

10 CFR 50.82(3) allows a licensee to complete decommissioning activities up to 60 years from cessation of power operations.

10 CFR Part 50, Appendix A, Criterion 62 requires, "Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations."

10 CFR 50.68(b)(1) requires, "Plant procedures shall prohibit the handling and storage at any one time of more fuel assemblies than have been determined to be safely subcritical under the most adverse moderation conditions feasible by unborated water."

10 CFR 50.68(b)(2) requires, "The estimated ratio of neutron production to neutron absorption and leakage (k-effective) of the fresh fuel in the fresh fuel storage racks shall be calculated assuming the racks are loaded with fuel of the maximum fuel assembly reactivity and flooded with unborated water and must not exceed 0.95, at a 95 percent probability, 95 percent confidence level. This evaluation need not be performed if administrative controls and/or design features prevent such flooding or if fresh fuel storage racks are not used."

10 CFR 50.68(b)(3) requires, "If optimum moderation of fresh fuel in the fresh fuel storage racks occurs when the racks are assumed to be loaded with fuel of the maximum fuel assembly reactivity and filled with low-density hydrogenous fluid, the k-effective corresponding to this optimum moderation must not exceed 0.98, at a 95 percent probability, 95 percent confidence level. This evaluation need not be performed if administrative controls and/or design features prevent such moderation or if fresh fuel storage racks are not used."

10 CFR 50.68(b)(4) requires, "If no credit for soluble boron is taken, the k-effective of the spent fuel storage racks loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95-percent probability, 95-percent confidence level, if flooded with unborated water. If credit is taken for soluble boron, the k-effective of the spent fuel storage racks loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95 percent probability, 95-percent confidence level, if flooded with borated water, and the k effective must remain below 1.0 (subcritical), at a 95-percent probability, 95-percent confidence level, if flooded with unborated water."

10 CFR 50.36(c)(4) requires, "Design features. Design features to be included are those features of the facility such as materials of construction and geometric arrangements, which, if altered or modified, would have a significant effect on safety and are not covered in categories described in paragraphs (c) (1), (2), and (3) of this section."

Background

On April 7, 2016, the NRC issued Generic Letter (GL) 2016-01, "Monitoring of Neutron-Absorbing Materials in Spent Fuel Pools" (ADAMS Accession No. ML16097A169), to address the degradation of neutron-absorbing materials (NAMs) in wet storage systems for reactor fuel at power and non-power reactors. The generic letter requested that licensees provide information to allow the NRC staff to verify continued compliance through effective monitoring to identify and mitigate any degradation or deformation of NAMs credited for criticality control in spent fuel pools (SFPs).

By letter dated November 3, 2016 (ADAMS Accession No. ML16319A131), as supplemented by letter dated February 8, 2018 (ADAMS Accession No. ML18039A843), Entergy responded to GL 2016-01 for Pilgrim. In Entergy's response to GL 2016-01, as supplemented, the licensee also identified that 2016 testing on the Boraflex installed in the SFP at Pilgrim showed that some of the Boraflex was no longer bounded by the nuclear criticality safety analysis of record. This resulted in the licensee implementing corrective actions to manage Boraflex degradation and maintain subcriticality in the SFP. On September 26, 2018, the NRC issued a letter to Entergy regarding the closeout of GL 2016-01. The letter states that the NRC staff found interim corrective actions taken to be adequate, and that the licensee-identified non-conservative TS would be

resolved per Administrative Letter 98 10, “Dispositioning of Technical Specifications That Are Insufficient to Assure Plant Safety,” dated December 29, 1998 (ADAMS Accession No. ML031110108).

Issue

The current and the proposed TS 4.3.1.1.a. both state the following:

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum k-infinity of 1.32 for standard core geometry, calculated at the burnup of maximum bundle reactivity, and an average U-235 enrichment 4.6% average over the axial planar zone of highest average enrichment; and

Because of the degraded neutron absorption capability of the Boraflex in the spent fuel pool racks, the TS maximum allowable infinite lattice multiplication factor (k-inf) of 1.32 will no longer bound the effective multiplication factor (k-eff) of 0.95, to ensure spent fuel pool conditions remain sufficiently sub-critical.

Request for Additional Information

NRR-SNPB-01

a. Provide the controls that ensure the Pilgrim SFP will meet the regulatory requirements for sub-criticality for the entire service life of the Pilgrim SFP.

b. Provide the analysis that demonstrates those controls will ensure the Pilgrim SFP will meet the regulatory requirements for sub-criticality for the entire service life of the Pilgrim SFP.

Hearing Identifier: NRR_DRMA
Email Number: 26

Mail Envelope Properties (BL0PR0901MB373107108BC5B1503594CC75FA140)

Subject: RAI - Pilgrim Post-Decommissioning Technical Specifications (PDTS) License Amendment Request (LAR) (EPID: L-2018-LLA-0268)
Sent Date: 6/3/2019 7:14:50 AM
Received Date: 6/3/2019 7:14:00 AM
From: Lamb, John

Created By: John.Lamb@nrc.gov

Recipients:
"Byrne, Robert M" <rbyrne@entergy.com>
Tracking Status: None
"Powers, Michael J" <mpower1@entergy.com>
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"Couture III, Philip" <pcoutur@entergy.com>
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Post Office: BL0PR0901MB3731.namprd09.prod.outlook.com

Files	**Size**	**Date & Time**
MESSAGE	7965	6/3/2019 7:14:00 AM

Options
Priority: High
Return Notification: No
Reply Requested: No
Sensitivity: Normal
Expiration Date:
Recipients Received:

Entergy Nuclear Operations, Inc.
1340 Echelon Parkway
Jackson, MS 39213
Tel 601-368-5573

Ronald W. Gaston
Director, Nuclear Licensing

2.19.047

July 16, 2019

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

SUBJECT: Response to Request for Additional Information – License Amendment Request to Revise the Pilgrim Nuclear Power Station Technical Specifications – Permanently Defueled Technical Specifications

Pilgrim Nuclear Power Station
NRC Docket No. 50-293
Renewed Facility Operating License No. DPR-35

REFERENCES:

1. Entergy Nuclear Operations, Inc. letter to NRC, "Technical Specifications Proposed Change - Permanently Defueled Technical Specifications," (ADAMS Accession No. ML18260A085), dated September 13, 2018

2. NRC email to Entergy Nuclear Operations, Inc., "Pilgrim: Request for Additional Information (RAI) – Pilgrim Post-Decommissioning Technical Specifications (PDTS) License Amendment Request (LAR) (EPID: L-2018-LLA-0268)," (ML19154A524), dated June 3, 2019

Entergy Nuclear Operations, Inc. (Entergy) submitted a License Amendment Request (LAR) to the U.S. Nuclear Regulatory Commission (NRC) for approval of the Permanently Defueled Technical Specifications, September 13, 2018 (Reference 1). A request for additional information was received from the NRC on June 3, 2019 (Reference 2).

Entergy is providing a response to the RAI in the enclosure to this letter.

The enclosed documentation contains proprietary information as defined by 10 CFR 2.390. Global Nuclear Fuels (GNF), as owner of the proprietary information, has executed the enclosed affidavit, which identifies that the enclosed proprietary information has been handled and classified as proprietary, is customarily held in confidence, and has been withheld from public disclosure. The proprietary information was provided to Pilgrim Nuclear Power Station (Entergy) in a GNF transmittal that is referenced in the affidavit. The proprietary information has been faithfully reproduced in the enclosed such that the affidavit remains applicable. GNF hereby requests the enclosed proprietary information be withheld from public disclosure in accordance with the provisions of 10 CFR 2.390 and 9.17. A non-proprietary version of the documentation also is provided.

This letter contains no new commitments and no revisions to existing commitments. If you have any questions or require additional information, please contact Mr. Peter J. Miner at (508) 830-7127.

I declare under penalty of perjury that the foregoing is true and correct. Executed on July 16, 2019.

Respectfully,

RWG/fxm

Enclosure: Response to Request for Additional Information – License Amendment Request to Revise the Pilgrim Nuclear Power Station Technical Specifications – Permanently Defueled Technical Specifications

Attachment to Enclosure:

GNF Letter KGO-ENO-HK1-19-058, "Pilgrim Rev 0 Response on Boraflex CSA RAI," July 1, 2019.

GNF Letter Enclosures:

1) Pilgrim Nuclear Power Station: Fuel Storage Criticality Safety Analysis of Spent Fuel Storage Racks to Remove Boraflex Credit - RAI Response Proprietary

2) Pilgrim Nuclear Power Station: Fuel Storage Criticality Safety Analysis of Spent Fuel Storage Racks to Remove Boraflex Credit - RAI Response Non-Proprietary

3) KGO-ENO-HK1-19-058 Affidavit

cc: USNRC Regional Administrator, Region I
USNRC Project Manager, Pilgrim
USNRC Resident Inspector, Pilgrim
Planning and Preparedness Section Chief, Massachusetts Emergency Management Agency
Director, Massachusetts Department of Public Health, Radiation Control Program

Enclosure

2.19.047

Response to Request for Additional Information – License Amendment Request to Revise the Pilgrim Nuclear Power Station Technical Specifications – Permanently Defueled Technical Specifications

Response to Request for Additional Information
License Amendment Request to Revise the Pilgrim Nuclear Power Station Technical Specifications –
Permanently Defueled Technical Specifications

NRC REQUEST FOR ADDITIONAL INFORMATION (RAI)

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Background

On April 7, 2016, the NRC issued Generic Letter (GL) 2016-01, "Monitoring of Neutron-Absorbing Materials in Spent Fuel Pools" (ML16097A169), to address the degradation of neutron-absorbing materials (NAMs) in wet storage systems for reactor fuel at power and non-power reactors. The generic letter requested that licensees provide information to allow the NRC staff to verify continued compliance through effective monitoring to identify and mitigate any degradation or deformation of NAMs credited for criticality control in spent fuel pools (SFPs).

By letter dated November 3, 2016 (ML16319A131), as supplemented by letter dated February 8, 2018 (ML18039A843), Entergy responded to GL 2016-01 for Pilgrim. In Entergy's response to GL 2016-01, as supplemented, the licensee also identified that 2016 testing on the Boraflex installed in the SFP at Pilgrim showed that some of the Boraflex was no longer bounded by the nuclear criticality safety analysis of record. This resulted in the licensee implementing corrective actions to manage Boraflex degradation and maintain subcriticality in the SFP. On September 26, 2018, the NRC issued a letter to Entergy regarding the closeout of GL 2016-01. The letter states that the NRC staff found interim corrective actions taken to be adequate, and that the licensee-identified non-conservative TS would be resolved per Administrative Letter 98-10, "Dispositioning of Technical Specifications That Are Insufficient to Assure Plant Safety," dated December 29, 1998 (ML031110108).

Entergy's corrective actions for this issue were inspected by the NRC and the results of the inspection are documented in integrated inspection report 05000293/2019001 (ML19133A225) dated May 13, 2019. No deficiencies or safety concerns were noted.

Issue

The current and the proposed TS 4.3.1.1.a. both state the following:

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum k-infinity of 1.32 for standard core geometry, calculated at the burnup of maximum bundle reactivity, and an average U-235 enrichment 4.6% average over the axial planar zone of highest average enrichment; and

Because of the degraded neutron absorption capability of the Boraflex in the spent fuel pool racks, the TS maximum allowable infinite lattice multiplication factor (k-inf) of 1.32 will no longer bound the effective multiplication factor (k-eff) of 0.95, to ensure spent fuel pool conditions remain sufficiently sub-critical.

NRR-SNPB-01.a

Provide the controls that ensure the Pilgrim SFP will meet the regulatory requirements for sub-criticality for the entire service life of the Pilgrim SFP.

ENTERGY RESPONSE

The Pilgrim Nuclear Power Station (PNPS) spent fuel pool (SFP) contains fourteen storage racks. Nine of these storage racks are Boraflex, four are Boral and one is Metamic. The Criticality Safety Analysis (CSA) performed to support maintaining the k-effective of fuel stored in the Boraflex SFP racks less than 0.95 does not credit the neutron absorption properties of the boron present in the Boraflex storage racks. The CSA requires that the Boraflex racks be zoned into Region 2, one cell in four of a 2x2 array empty, or Region 3, two cells in four of a 2x2 array empty (checkerboard). In addition, only fuel analyzed for storage in either Region 2 or 3 may be stored in the Boraflex racks. The fuel removed from the reactor vessel following permanent shutdown was stored in the Boral or Metamic racks which have been analyzed to store the most reactive peak reactivity bundle in the PNPS SFP.

The CSA evaluated the adequacy of the Region 2 and Region 3 zones in the Boraflex racks. A station procedure implements the configuration controls used to ensure that the requirements of the CSA are maintained as follows:

#1 Reconfigure the SFP Boraflex Racks into Regions 2 and 3 configurations. Ensure Region 2 is loaded having one empty location out of every 2X2 array. Ensure Region 3 is loaded having two empty locations out of every 2X2 array. Load Regions 2 and 3 in the SFP Boraflex racks with fuel eligible for loading into the respective region in accordance with the CSA. Ensure that locations required to be empty do not contain a fuel bundle by documented verification of the SFP Boraflex rack configuration.

#2 Block the locations adjacent to Panel RR35 South with blade guides.

Row ↓ Column →	34	35
RR	X	X

Defective Panel RR35 South

X = locations to be blocked by Blade Guides

#3 Administrative Controls outlined below are also established to prevent inadvertant installation of an incorrect fuel bundle into the Boraflex racks.

a. Additional review by a qualified reviewer for move sheet preparation for fuel movement within the Boraflex racks,

b. Post Defueling, a Certified Fuel Handler will directly supervise fuel movement in the Spent Fuel Pool.

These administrative controls and the required region configurations have been incorporated into station procedure 4.3, "Fuel Handling." This procedure implements these controls and requires verification of the fuel stored in the Boraflex racks whenever fuel is moved within or into these racks. This verification is to ensure that the correct fuel is stored in the correct configuration as required by the CSA. The updated Special Nuclear Material records, SFP Item Control Area account area form, based upon the completed fuel movement sheets is compared to the as left condition of the fuel in the Boraflex racks and to the region bundle listing and region definitions established in the CSA. This activity ensures that the correct fuel is stored in the correct configuration to maintain keff less than 0.95.

Panel RR35 South is the only Boraflex storage panel found by testing to have experienced large gap growth. As a conservative measure, even though the Boraflex racks have been analyzed without credit for the boron absorber, the cells adjacent to RR35 South are required to be blocked by storing blade guides in these cells. All other measured Boraflex panels were found to be within the bounds of the original CSA.

Prescriptive procedural requirements, extensive use of human performance tools and direct supervisory oversight have been successful at PNPS in avoiding fuel handling errors, such as misplaced fuel bundles. PNPS has successfully moved fuel over the past three years using the above referenced configuration controls to maintain SFP subcritical margin.

Non-Boraflex racks in the spent fuel pool are not susceptible to formation of gaps found in the Boraflex racks. Therefore, these racks are not required to be configured into fuel storage protection regions to ensure SFP criticality requirements. Fuel in cells of any Boral and Metamic racks can be moved as required using the procedure controls identified in station procedure 4.3. These SFP storage racks may be used to store the most reactive peak reactivity bundles in the PNPS SFP. The interface between the Boraflex racks and the Boral/Metamic racks was evaluated based on actual peak reactivity of the PNPS fuel. The reactivities used bound all of the fuel currently stored in the SFP.

Aging management controls applicable to the SFP and associated SFP storage racks consist of the Water Chemistry Control – BWR Program that is described in UFSAR, Appendix S, Section S.2.37 and the Structures Monitoring Program, described in UFSAR, Appendix S, and Section S.2.32. These aging management programs are implemented by station procedure 7.8.1, "Chemistry Sample and Analysis Program," and station procedure P-EN-DC-150, "Condition Monitoring of Maintenance Rule Structures." These programs ensure that the SFP

racks and SFP are exposed to a treated water environment and are monitored for potential degradation. NRC staff evaluation of these aging management programs is documented in SER Sections 3.0.3.1.13 and 3.0.3.2.17 respectively (see Enclosure reference 1).

PNPS also maintains a Neutron Absorber Monitoring Program for the Boral and Metamic racks as part of the aging management program. This program is described in UFSAR, Appendix S, Section S.2.41 and involves coupon sampling and sample material evaluation. The most recent coupons, one Boral and one Metamic, were removed from the SFP in late 2018 and were analyzed in early 2019. The coupons were found to be in good condition with test results meeting identified acceptance criteria. Coupons are removed and analyzed at a frequency established by station procedure 4.8, "Spent Fuel Pool Storage Rack Coupon Retrieval." These surveillance controls ensure that the Boral and Metamic spent fuel racks are monitored and maintained for the expected service life of the SFP. Attachment 1 to station procedure 4.8 identifies that the next coupon sample tests were scheduled to be performed in 2023. However, the transfer of spent fuel to dry cask storage is planned to be completed no later than 2022 based on the current schedule identified in the previously submitted Post Shutdown Decommissioning Activity Reports (see Enclosure references 2 and 3)

NRR-SNPB-01.b

Provide the analysis that demonstrates those controls will ensure the Pilgrim SFP will meet the regulatory requirements for sub-criticality for the entire service life of the Pilgrim SFP.

ENTERGY RESPONSE

b) See Attached - GNF Letter KGO-ENO-HK1-19-058, "Pilgrim Rev 0 Response on Boraflex CSA RAI," July 1, 2019.

   Note: Enclosure 1 to the attached letter contains GNF Proprietary Information and is withheld from public disclosure per 10 CFR 2.390.

References

1. Letter, USNRC to Entergy, "Safety Evaluation Related to the License Renewal of Pilgrim Nuclear Power Station, ", (ML071410455), dated June 28, 2007.

2. Letter, Entergy Nuclear Operations, Inc. to USNRC, "Post Shutdown Decommissioning Activities Report, Pilgrim Station", 2.18.070, (ML18320A034), dated November 16, 2018

3. Letter, Holtec Decommissioning International to USNRC, "Notification of Revised Post Shutdown Decommissioning Cost Estimate for Pilgrim Nuclear Power Station," (ML18320A040), dated November 16, 2018

Enclosure, Attachment

2.19.047

GNF Letter KGO-ENO-HK1-19-058, "Pilgrim Rev 0 Response on Boraflex CSA RAI," July 1, 2019.

ENCLOSURE 2

KGO-ENO-HK1-19-058

Pilgrim Nuclear Power Station:
Fuel Storage Criticality Safety Analysis
of Spent Fuel Storage Racks
to Remove Boraflex Credit – RAI Response

Non-Proprietary Information

INFORMATION NOTICE

This is a non-proprietary version of Enclosure 1 of KGO-ENO-HK1-19-058, which has the proprietary information removed. Portions of the document that have been removed are indicated by white space inside open and closed bracket as shown here [[ ]].

Global Nuclear Fuel

005N3339
Revision 0
July 2019

Non-Proprietary Information

Pilgrim Nuclear Power Station: Fuel Storage Criticality Safety Analysis of Spent Fuel Storage Racks to Remove Boraflex Credit – RAI Response

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IMPORTANT NOTICE REGARDING CONTENTS OF THIS REPORT

Please Read Carefully

Revision Status

Revision Number	Date	Description of Change
0	July 2019	Initial Release

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List of Figures

1.0 RAI RESPONSE

GNF has performed a full scope criticality safety analysis to define Bundle ID specific storage eligibility in Boraflex racks at Pilgrim Nuclear Power Station (PNPS) without any Boraflex credited in the rack design. The analysis covers all fuel discharged from Pilgrim that is currently in the spent fuel pool. Fuel that was operating in Cycle 22 (C22) at the time of the analysis was also evaluated; however, the decision was subsequently made to preclude Cycle 22 discharged assemblies from storage in any cell in the Boraflex racks. This reduces the number of assemblies with significant residual reactivity from storage consideration, improving margin in the Boraflex rack system. This response provides a summary of the analysis with two purposes:

A. Describe the overall evaluation approach and associated rack/fuel models to provide confidence that the methods utilized provide a conservative representation of system reactivity, and

B. Demonstrate significant margin to the subcriticality limit for all eligible assemblies in each Region of the Boraflex racks.

The analysis is divided into three evaluations, with associated models and results summarized in Table 1.

Table 1 – Summary of Evaluation Methods and Results

Evaluation Number	Fuel Evaluated	Fuel Model	Rack Model	$K_{nominal}$(1)	K_{max} (95/95)	# of Eligible Assemblies
1	Single Bounding Lattice	Model A – Peak Reactivity	Region 3 (2/4)	[[		
2	Lattices Bounding LJ4XXX/LJ5XXX Bundle IDs	Model A – Peak Reactivity	Region 2 (3/4)			
3	All Bundle IDs Discharged After [[ ]](2)	Model B – Burn-up Credit	Region 2 (3/4)			]]

Notes:

1. [[ ]]
2. See Appendix A for histograms of Bundle ID Specific values for eligible assemblies.

In these Evaluations, the calculation of appropriate adder terms and a statistical roll-up of results to define K_{max} (95/95) values is performed in a manner consistent with guidance in Reference 1, as summarized in the Equations below.

$$K_{max}(95/95) = K_{nominal} + \Delta k_{Bias} + \Delta k_{Uncertainty} + \Delta k_{Interface}$$

Where:

$$\Delta k_{Bias} = \sum_{i=1}^{n} \Delta k_{Bi} \qquad \Delta k_{Uncertainty} = \sqrt{\sum_{i=1}^{n} \Delta k_{Ui}^2}$$

Additional details on the fuel and rack models used in each case are provided in the evaluation specific sections that follow. These sections also summarize the manner in which the adder terms were developed and applied in each evaluation. Where appropriate, some of the more technical details of the work are provided as Appendices to allow for a summary of the approach and results to be presented in a more streamlined way. The response closes with a discussion of analysis conclusions.

Evaluation Descriptions

Evaluation 1 – Bounding Peak Reactivity Lattice in Checkerboard Loading Pattern

The first evaluation leverages a traditional peak, reactivity analysis method. The method utilized is consistent with GNF's typical fuel rack criticality analysis approach that has been described in detail in recent license amendment requests [2]. In these calculations, a single assembly is modeled in every eligible storage location. The assembly is modeled such that its entire axial length is assumed to exist at the exposure dependent, peak reactivity state corresponding to the bounding two-dimensional (2D) lattice of the limiting nuclear design, also referred to in the analysis as "Fuel Model A". The bounding lattice modeled was selected based on a survey of all fuel at Pilgrim, as discussed in Appendix C.

This approach is used to define eligibility for all bundles in the pool in a checkerboard configuration (i.e., 2/4 loading pattern or "Region 3"). The rack model definition used in the analysis is further described in Appendix D.

This evaluation calculates biases and uncertainties in a manner that is consistent with guidance in Reference 1 and as described more specifically in Reference 2. [[

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Evaluation 2 – Low Reactivity Fuel Designs Modeled at Peak Reactivity in 3/4 Loading Pattern

The second evaluation is also a traditional, peak reactivity analysis with a fuel modeling approach that is consistent with Evaluation 1 (i.e., Fuel Model A); however, in this case two different unique nuclear designs[1] are evaluated. The nuclear designs analyzed are consistent with the design used for all Bundle IDs that start with "LJ4" and "LJ5". These designs were selected for additional evaluation based on their low peak reactivity characteristics, as discussed in Appendix C.

The assemblies were evaluated in a more densely packed loading pattern (i.e., 3/4 loading pattern or Region 2) than was used in Evaluation 1. The rack model definition used in the analysis is also described in Appendix D.

Again, similar to 1, this evaluation calculates biases and uncertainties for each of the two unique nuclear designs evaluated in a manner that is consistent with guidance in Reference 1 and as described more specifically in Reference 2. [[

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Evaluation 3 – Well Characterized Fuel Modeled with Burn-up Credit in 3/4 Loading Pattern

[1] A "unique nuclear design" is defined as a bundle that has a consistent fuel product and fuel loading pattern combination

In the third evaluation, assemblies are modeled on a Bundle ID specific basis with explicit nodal discharge exposure profiles that are associated with that unique assembly's local operational conditions. These local conditions are defined by GNF's core simulator code, PANAC11. The use of such a three-dimensional (3D) model with best-estimate nodal isotopics in a criticality safety analysis is commonly referred to as a "burn-up credit method", or "Fuel Model B" in this analysis. Additional details on the mechanics behind the construction of these fuel models is provided in Appendix E of this response.

In each case, the assemblies were evaluated in the same loading pattern as Evaluation 2 (i.e., 3/4 loading pattern or Region 2).

This method requires a unique calculation for every Bundle ID analyzed to define its $K_{nominal}$ value. In these calculations, the assembly of interest is modeled in every eligible storage location. Evaluating the system in this way ensures any combination of eligible bundles stored in a given region will result in a system reactivity that is less than the maximum reactivity calculated in these infinite, homogenous studies. For the PNPS analysis, this required [[ ]] individual in-rack cases to be calculated.

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Note: [[ ]]

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Interface Considerations

Interfaces between different combinations of Region 2 and Region 3, as well as interfaces between these Regions and adjacent non-Boraflex racks, were explicitly evaluated. These interface evaluations included consideration of a misload assembly in a position to maximize the reactivity of the interface region of the system. Results from these studies demonstrated that interfaces did not result in significant increases in system reactivity compared to the reactivity of their constituent Regions, confirming that no additional restrictions were necessary on loading patterns to maintain reactivity margin in the spent fuel pool.

Analysis Conclusions

The results from all three evaluations were used to define Bundle ID specific eligibility in each Region of the Boraflex racks. This eligibility was presented as a simple table in the final report, where each Bundle ID in the Pilgrim spent fuel pool was characterized as either acceptable or not acceptable for storage in Region 2 and Region 3.

As shown in Table 1 and Appendix A, there is significant margin to the regulatory limit of 0.95 for all eligible assemblies in both Regions of Boraflex racks with no credit taken for Boraflex neutron absorption in the analysis.

References

1. NEI 12-16 Revision 3, "Guidance for Performing Criticality Analyses of Fuel Storage at Light-Water Reactor Power Plants," March 2018. (NRC ADAMS Accession Number ML18088B400).
2. NEDC-33886P, "River Bend Station: Fuel Storage Criticality Safety Analysis of Spent Fuel Storage Racks with Rack Inserts," Revision 1, October 2018 (NRC ADAMS Accession Number ML18297A103).
3. NUREG/CR-7108," An Approach For Validating Actinide and Fission Product Burnup Credit Criticality Safety Analyses – Isotopic Composition Predictions", April 2012.
4. Metwally, W., Sugawara, M., Mills, V., Hannah, J., "TGBLA Spent Fuel Isotopic Predictions And Their Effect on Criticality Calculations", in proceedings of *PHYSOR 2010*, Pittsburg, Pennsylvania, USA, May 9-14, 2010, (2010).
5. NUREG/CR-7162, "Analysis of Experimental Data for High Burnup BWR Spent Fuel Isotopic Validation – SVEA-96 and GE14 Assembly Designs", March 2013.

APPENDIX A – $K_{nominal}$ AND K_{max} (95/95) DISTRIBUTIONS FOR ELIGIBLE ASSEMBLIES IN EVALUATION 3

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Figure 1 – Nominal In-Rack Reactivities of Eligible Assemblies from Evaluation 3 (BUC + Region 2)

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Figure 2 - K_{max} (95/95) of Eligible Assemblies from Evaluation 3 (BUC + Region 2)

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APPENDIX C – PEAK INFINITE LATTICE REACTIVITY OF PILGRIM BUNDLES

Table 3 provides in-core k_∞ results calculated by TGBLA06 for each bundle at Pilgrim. The values shown correspond to the peak reactivity lattice of each bundle at its peak reactivity exposure.

The assembly corresponding to the **bold** values at the top of the table on the left were selected for modeling in Evaluation 1. The assemblies corresponding to the *italicized* values at the bottom of the table on the right were selected for modeling in Evaluation 2.

Table 2 – Maximum In-Core k_∞ of Bundles at Pilgrim

Bundle Number	Lattice Number(1)	Peak In-Core k_∞	Bundle Number	Lattice Number	Peak In-Core k_∞
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Note 1: [[

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APPENDIX D – RACK REGION DEFINITIONS AND CALCULATION MODELS

The full scope criticality analysis establishes, on a Bundle ID specific basis, which assemblies are eligible for storage in the following configurations in the plant's Boraflex racks:

1. Region 2: Bundles stored in 3 out of every 4 cells – i.e., 3/4
2. Region 3: Bundles stored in 2 out of every 4 cells – i.e., 2/4

A "fully loaded" Region 1 (i.e., 4/4 loading pattern) is not allowed in the Boraflex racks.

Conservative models of the rack systems were developed that are defined by the following characteristics:

1. An array of 8x8 cells with periodic boundary conditions in the x and y axes to preclude leakage in the radial direction,
2. Twelve inches of water above and below the active fuel to limit axial leakage of neutrons,
3. Explicit modeling of rack structural material in the active fuel region with the minimum pitch between storage cells that can result from the combination of different sub-elements of the rack design,
4. Removal of all Boraflex from the system (replaced with water), and
5. Cells which are precluded from fuel storage are modeled with a physical blocking device, [[
]]. This blocking device is modeled based on the cross section of a GE blade guide in the active fuel region. Studies were performed to demonstrate explicit modeling of this device results in an increase in system reactivity; therefore, final configurations that do or do not contain a blocking device are acceptable from a criticality calculation perspective.

A radial cross-section of the associated Region 2 and Region 3 rack models are provided in Figure 3 and Figure respectively. The empty locations (blue color) are filled with water and the cell blocking device.

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Figure 3 – Region 2 Rack Model

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Figure 4 – Region 3 Rack Model

APPENDIX E - FUEL MODEL B – BURN-UP CREDIT METHOD

The burn-up credit fuel model is developed using the following procedure:

1. Exposure Accounting – Using actual plant operating history, perform exposure accounting for Cycles [[ ]]
2. Nodal History Collapsing - Collapse historical operational data into nodal depletion history on a discharge bundle specific basis.
3. Nodal Isotopic Definition - Reburn each node of the analyzed discharged bundles using its collapsed operational history with TGBLA06.
4. MCNP Input Generation - Combine 2D lattice physics defined pin specific isotopic outputs into 3D MCNP bundle input files on a Bundle ID specific basis.

Additional details on each step in the Fuel Model development process are provided in the sections that follow. An overall flowchart of this process, including details on how it fits into the overall evaluation method, are provided at the end of this Appendix in Figure 7.

Exposure Accounting

In order to quantify the reactivity of a spent fuel assembly, it is necessary to account for the operational history that the individual bundle experienced throughout its time in the core. For a large number of historical cycles for a given BWR, the history of a plant's operation is available either in plant records or on GNF's Boiling Water Reactor Engineering Data Bank (BWREDB). The information is most commonly available on either daily or weekly intervals. This plant operational history typically includes, among other things, core power, core flow rate, and control blade positions as a function of exposure for a given cycle. Using this information, GNF's nodal core simulator PANAC11 can be used to calculate the following information on a nodal basis for a corresponding fine exposure grid:

1. Exposure
2. Instantaneous Void Fraction
3. Fuel Temperature
4. Control State
5. Power Density

As is common for BWR nodal core simulators, each node is defined as an approximately 6-inch cube in the calculation method. For Pilgrim, the active fuel height is 145.24 inches tall divided evenly into 24 nodes that are slightly larger than 6 inches. This process of defining historical nodal conditions as a function of core operation is commonly referred to as exposure accounting and is performed on a regular basis as a part of the core design process, where the local reactivity definitions of reinserted bundles are essential for planning the next core design at the plant.

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Nodal History Collapsing

The outcome of exposure accounting is a database which contains the history of nodal conditions for a given bundle in the spent fuel pool. This history often includes hundreds of exposure steps for each node. In order to be able to practically handle this information with a depletion code, this information is collapsed into 1 GWD/STU exposure steps. The collapsing is performed on an exposure-weighted basis for all of the parameters relevant to the node's depletion (i.e., items 2-5 in the previous section). Note that, given the control state input is binary (controlled or uncontrolled) for the 2D lattice physics calculations, the control state which defines the majority of the 1 GWD/STU step is used to characterize the entire step. The use of this best estimate approximation has a small effect on local reactivity and is appropriate because there is no a priori conservative control state to select at any given point in a node's exposure accumulation as it relates to discharge reactivity.

Depletion on an exposure grid that is at least this fine is consistent with generally accepted practices for lattice physics codes and provides sufficient detail to adequately account for the changes in isotopics and the corresponding effect on physics parameters. Note that a final step is taken to the calculated discharge exposure (off the 1 GWD/STU grid) in this collapsing process to accurately reflect the actual 3D discharge exposure profile of the bundle. A graphical representation of this collapsing method is provided in Figure 5.

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Figure 5 – Illustration of Collapsed Void Fraction versus Explicit Void Fraction History

Nodal Isotopic Definition

The collapsed operational history data is used in conjunction with explicit bundle geometry and fuel loading information available on the BWREDB to define lattice physics inputs on the collapsed exposure grid for any unique assembly in the pool. Because any unique assembly can be explicitly modeled, the development of representative geometry or operational history definitions for application to large populations of assemblies is not required.

A single lattice physics input is created for each node (typically 24 or 25) in a bundle using this approach. These lattice physics inputs are executed in GNF's lattice physics code, TGBLA06, to generate pin specific isotopics on a nodal basis at the time of discharge for a given assembly. Because this process used the operating history of each node to perform the depletions, history parameters, such as void history or control history, are implicitly included in the depletion and do not need to be separately addressed.

The lattice physics code also has the capacity to assess the isotopic content as a function of decay time to allow for an explicit accounting of cooling time. This feature is leveraged in this evaluation such that the nodal isotopics are provided for evaluation in the storage rack assuming bundles have experienced isotopic decay from the time of their discharge to June 1, 2018.

MCNP Input Generation

The TGBLA06 defined geometry and pin specific isotopics for any node are translated to 2D MCNP inputs using a GNF utility code similar to the peak reactivity method. The 2D inputs are combined into 3D bundle inputs with the same nodal structure used in the core simulator. For those regions of the bundle where geometry is non-uniform in a node (i.e., hybrid nodes), the geometric heterogeneity is preserved in MCNP by adding an additional lattice physics simulation and MCNP translation to the process. This treatment results in a node in MCNP that is characterized by the same operational history but is subdivided based on geometry.

A graphical representation of a 3D bundle generated with this method that demonstrates these features is provided in Figure 6. In this figure, each color represents a unique cell and material definition defined in this process. [[

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Figure 6 – MCNP-05P Plots of Fuel Model B Geometry

Again, like the peak reactivity method, this fuel model is combined with the 3D MCNP rack definition to allow for each unique bundle to be analyzed as if it existed in every eligible storage location in the pool. Executing these inputs in MCNP allows for the definition of bounding in-rack reactivities for any bundle with sufficiently detailed operational history. [[

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Figure 7 – Evaluation 3 Method Flow Chart

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APPENDIX F – KMAX (95/95) ADDER STUDIES FOR EVALUATION 3

As was done in Evaluation 1 and Evaluation 2, Evaluation 3 calculates biases and uncertainties in a manner that is generally consistent with guidance in Reference 1 and as described more specifically in Reference 2, [[

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In this case, however, it is necessary to consider additional uncertainties to account for the increased modeling complexity and higher exposures that are explicitly evaluated. The additional biases and uncertainties considered are described in more detail below.

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a. [[

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b. [[

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ENCLOSURE 3

KGO-ENO-HK1-19-058

Affidavit

Global Nuclear Fuel – Americas

AFFIDAVIT

I, Brian R. Moore, state as follows:

(1) I am the General Manager, Core & Fuel Engineering, Global Nuclear Fuel – Americas, LLC ("GNF-A"), and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in Enclosure 1 of GNF's letter KGO-ENO-HK1-19-058, Kimberly O'Connor to Edward Sanchez (Entergy Nuclear Operations, Inc), entitled "Pilgrim Nuclear Power Station: Fuel Storage Criticality Safety Analysis of Spent Fuel Storage Racks to Remove Boraflex Credit – RAI Response, June 2019. GNF proprietary information in Enclosure 1 is identified by a dotted underline inside double square brackets. [[This sentence is an example.{3}]] A "[[" marking at the beginning of a table, figure, or paragraph closed with a "]]" marking at the end of the table, figure or paragraph is used to indicate that the entire content between the double brackets is proprietary. In each case, the superscript notation {3} refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination.

(3) In making this application for withholding of proprietary information of which it is the owner or licensee, GNF-A relies upon the exemption from disclosure set forth in the Freedom of Information Act ("FOIA"), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), and 2.390(a)(4) for "trade secrets" (Exemption 4). The material for which exemption from disclosure is here sought also qualify under the narrower definition of "trade secret", within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) Some examples of categories of information which fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by GNF-A's competitors without license from GNF-A constitutes a competitive economic advantage over other companies;

b. Information which, if used by a competitor, would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

c. Information which reveals aspects of past, present, or future GNF-A customer-funded development plans and programs, resulting in potential products to GNF-A;

d. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

The information sought to be withheld is considered to be proprietary for the reasons set forth in paragraphs (4)a. and (4)b. above.

(5) To address 10 CFR 2.390 (b) (4), the information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GNF-A, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GNF-A, no public disclosure has been made, and it is not available in public sources. All disclosures to third parties including any required transmittals to NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence. Its initial designation as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in paragraphs (6) and (7) following.

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge, or subject to the terms under which it was licensed to GNF-A.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist or other equivalent authority, by the manager of the cognizant marketing function (or his delegate), and by the Legal Operation, for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GNF-A are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary agreements.

(8) The information identified in paragraph (2) is classified as proprietary because it contains details of GNF-A’s fuel design and licensing methodology.

The development of the methods used in these analyses, along with the testing, development and approval of the supporting methodology was achieved at a significant cost to GNF-A or its licensor.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GNF-A's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GNF-A's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical, and NRC review costs comprise a substantial investment of time and money by GNF-A.

The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial.

GNF-A's competitive advantage will be lost if its competitors are able to use the results of the GNF-A experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GNF-A would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GNF-A of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing and obtaining these very valuable analytical tools.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 1st day of July 2019.

Brian R. Moore

Brian R. Moore
General Manager, Core & Fuel Engineering
Global Nuclear Fuel – Americas, LLC
3901 Castle Hayne Road
Wilmington, NC 28401
Brian.Moore@ge.com

From: Wall, Scott
Sent: Friday, July 26, 2019 2:33 PM
To: Couture III, Philip
Cc: Halter, Mandy; Miner, Peter; Manrique, Ricardo
Subject: Final RAI - Pilgrim License Transfer and Holtec DTF Exemption Requests (EPID: L-2018-LL0-0003 and L-2018-LLE-0020)

Dear Mr. Couture,

By application dated November 16, 2018 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML18320A031), as supplemented by letters dated November 16, 2018, and April 17, 2019 (ADAMS Accession Nos. ML18320A040 and ML19109A177, respectively), Entergy Nuclear Operations, Inc. (ENOI), on behalf of itself and Entergy Nuclear Generation Company (ENGC) (to be known as Holtec Pilgrim, LLC), Holtec International (Holtec), and Holtec Decommissioning International, LLC (HDI), (hereinafter referred to as "Applicants"), requested that the U.S. Nuclear Regulatory Commission (NRC) consent to the following actions:

(1) the indirect transfer of control of the Renewed Facility Operating License No. DPR-35 for the Pilgrim Nuclear Power Station (Pilgrim), as well as the general license for the Pilgrim Independent Spent Fuel Storage Installation (ISFSI), to Holtec, and

(2) the direct transfer of ENOI's operating authority to HDI.

The Applicants also requested that the NRC approve a conforming administrative amendment to the facility licenses, to reflect the proposed direct transfer of the licenses from ENOI to HDI and the planned name change for ENGC, from ENGC to Holtec Pilgrim, LLC (Holtec Pilgrim).

Additionally, in Enclosure 2 of the license transfer application dated November 16, 2018, HDI requested exemption from 10 CFR 50.82(a)(8)(i)(A). The exemption from 10 CFR 50.82(a)(8)(i)(A) would permit HDI to make withdrawals from the Pilgrim Decommissioning Trust Fund (DTF) for spent fuel management and site restoration activities in accordance with the site-specific Pilgrim Decommissioning Cost Estimate (DCE).

The U.S. Nuclear Regulatory Commission staff has reviewed the submittals and determined that additional information is needed to complete its review. The specific questions are found in the enclosed request for additional information (RAI). During a telephone call on July 26, 2019, the Entergy staff indicated that a response to the RAI would be provided within 10 days.

If you have questions, please contact me at 301-415-2855 or via e-mail at Scott.Wall@nrc.gov.

Scott P. Wall, LSS BB, BSP
Senior Project Manager
Plant Licensing Branch III
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation
301.415.2855
Scott.Wall@nrc.gov

Docket Nos. 50-293 and 72-1044

Enclosure:
Request for Additional Information

cc: Listserv

RAI-PFPB-1

REQUEST FOR ADDITIONAL INFORMATION

DIRECT AND INDIRECT TRANSFER OF LICENSE AND

CONFORMING LICENSE AMENDMENT AND REQUEST

FOR EXEMPTION FROM 10 CFR 50.82(a)(8)(i)(A)

ENTERGY NUCLEAR OPERATIONS, INC.

PILGRIM NUCLEAR POWER STATION

DOCKET NOS. 50-293 AND 72-1044

By application dated November 16, 2018 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML18320A031), as supplemented by letters dated November 16, 2018, and April 17, 2019 (ADAMS Accession Nos. ML18320A040 and ML19109A177, respectively), Entergy Nuclear Operations, Inc. (ENOI), on behalf of itself and Entergy Nuclear Generation Company (ENGC) (to be known as Holtec Pilgrim, LLC), Holtec International (Holtec), and Holtec Decommissioning International, LLC (HDI), (hereinafter referred to as “Applicants”), requested that the U.S. Nuclear Regulatory Commission (NRC) consent to the following actions:

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(2) the direct transfer of ENOI’s operating authority to HDI.

The Applicants also requested that the NRC approve a conforming administrative amendment to the facility licenses, to reflect the proposed direct transfer of the licenses from ENOI to HDI and the planned name change for ENGC, from ENGC to Holtec Pilgrim, LLC (Holtec Pilgrim).

In support of its license transfer application, HDI submitted a “Notification of Revised Post-Shutdown Decommissioning Activities Report and Revised Site-Specific Decommissioning Cost Estimate for Pilgrim Nuclear Power Station” (revised PSDAR) on November 16, 2018 (ADAMS Accession No. ML18320A040), to notify the NRC of changes to accelerate the schedule for the prompt decommissioning (i.e., DECON) of Pilgrim and unrestricted release of all portions of the site (excluding the ISFSI) within 8 years after the license transfer. On December 17, 2018 (ADAMS Accession No. ML18333A240), the NRC notified ENOI that the staff is treating the revised PSDAR submittal, dated November 16, 2018, as a supplement to the Pilgrim license transfer application, also dated November 16, 2018, until such time as the NRC makes a regulatory decision on the Pilgrim license transfer application. The NRC staff is reviewing the revised PSDAR only to determine whether Holtec Pilgrim and HDI are financially and technically qualified to hold the license for Pilgrim and the general license for the Pilgrim ISFSI, as described in the application, and to engage in the proposed maintenance and decommissioning activities associated with the Pilgrim site.

Additionally, in Enclosure 2 of the license transfer application dated November 16, 2018, HDI requested an exemption from 10 CFR 50.82(a)(8)(i)(A). The exemption from 10 CFR 50.82(a)(8)(i)(A) would permit HDI to make withdrawals from the Pilgrim Decommissioning Trust Fund (DTF) for spent fuel management and site

restoration activities in accordance with the site-specific Pilgrim Decommissioning Cost Estimate (DCE), included with the revised PSDAR.

The U.S. Nuclear Regulatory Commission staff reviewed the submittal and determined that the following additional information is needed to complete its review.

<u>RAI-PFPB-01</u>

<u>Applicable Regulation and Guidance</u>

In Title 10 of the Code of Federal Regulations (10 CFR) Part 50.75, “Reporting and recordkeeping for decommissioning planning,” the NRC establishes requirements for indicating to the NRC how a licensee will provide reasonable assurance that funds will be available for the decommissioning process. In addition, 10 CFR 50.75(b) requires that each power reactor applicant for an operating license submit a decommissioning report, as required by 10 CFR 50.33(k).

In 10 CFR 50.75(b)(1), the NRC states, in part, that:

> For an applicant for … an operating license under part 50, the report must contain a certification that financial assurance for decommissioning will be … provided in an amount which may be more, but not less, than the amount stated in the table in paragraph (c)(1) of this section …

In 10 CFR 50.75(b)(3), the NRC indicates that the amount determined by 10 CFR 50.75(c) must be covered one or more of the methods described in Section 50.75(e).

Further, 10 CFR 50.75(b)(4) states, in part:

> The amount stated in the applicant's… certification may be based on a cost estimate for decommissioning the facility….

In 10 CFR 50.75(c), the NRC provides the method acceptable to the agency for determining the minimum amount required to demonstrate reasonable assurance of funds for decommissioning by reactor type and power level; with adjustment factor.

In 10 CFR 50.75(e), the NRC includes the methods acceptable to the agency for providing decommissioning financial assurance.

Finally, 10 CFR 50.75(h) provides additional requirements on the management of decommissioning trust funds (DTFs).

10 CFR 50.33(f) states, in part:

> Except for an electric utility applicant for a license to operate a utilization facility of the type described in § 50.21(b) or § 50.22, [each application shall state] information sufficient to demonstrate to the Commission the financial qualification of the applicant to carry out, in accordance with regulations in this chapter, the activities for which the permit or license is sought.

The definition of “decommission” in 10 CFR 50.2 reads as follows:

> to remove a facility or site safely from service and reduce residual radioactivity to a level that permits—
> (1) Release of the property for unrestricted use and termination of the license; or
> (2) Release of the property under restricted conditions and termination of the license.

The regulation in 10 CFR 50.82(a)(8)(i)(A) restricts the use of DTF withdrawals to expenses for legitimate decommissioning activities consistent with the definition of decommissioning in 10 CFR 50.2. This definition in 10 CFR 50.2 does not include activities associated with spent fuel management and site restoration activities.

Regulatory Guide (RG) 1.202, "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors" (ADAMS Accession No. ML050230008), states, in part, that:

> [T]o meet the requirements of 10 CFR 50.75(c), a power reactor licensee may submit a certification based on a site-specific cost estimate, which may be more (but not less) than the amount specified in 10 CFR 50.75(b)(1)….

In addition, RG 1.202, states:

> … a site-specific estimate may be submitted, at the discretion of the licensee, when a funding level differs from that calculated in the formula in 10 CFR 50.75(c). The site-specific cost estimate must clearly identify and provide the basis for the funding level if it differs from the formula.

Further RG 1.202, indicates that the licensee should provide a comparison of the estimated decommissioning cost with the minimum financial assurance funding requirement of 10 CFR 50.75(c).

RG 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors" (ADAMS Accession No. ML112160012), states, in part, that:

> At its discretion, a power reactor licensee may submit a certification based either on the formulas provided in 10 CFR 50.75(c)(1) and (2) or, when a higher funding level is desired, on a site-specific cost estimate that is equal to or greater than that calculated in the formulas in 10 CFR 50.75(c)(1) and (2). A site-specific cost estimate may include non-NRC-required costs, but such costs should be identified. If such a combined submittal is used, licensees should ensure that the NRC-required cost estimate for decommissioning costs, as defined in 10 CFR 50.2, is equal to or greater than the amount stated in the formulas in 10 CFR 50.75(c)(1) and (2). For certification amounts below the amount stated in the formulas in 10 CFR 50.75(c)(1) and (2), licensees must submit an exemption request.…

The NRC staff also applied guidance in NUREG-1577, Revision 1, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance," issued February 1999 (ADAMS Accession No. ML013330264), to evaluate the financial qualifications of applicants to carry out the activities for which the permit or license is sought.

NUREG-1713, "Standard Review Plan for Decommissioning Cost Estimates for Nuclear Power Reactors," issued December 2004 (ADAMS Accession No. ML043510113), to evaluate decommissioning cost estimates provided by power reactor licensees. NUREG-1713, states in part, that:

> The [NRC] reviewer should compare the [site-specific DCE] with the minimum decommissioning financial assurance requirement amount derived per the algorithm discussed in [10 CFR 50.75(c)]. If the [site-specific DCE] is less than the amount derived from the algorithm in 10 CFR 50.75(c) and adequate justification is not provided, [the NRC] will inform the licensee in writing of additional information needed to resolve the deficiency.

Issue

By letter dated March 28, 2019 (ADAMS Accession No. ML19087A318), ENOI submitted its annual report on the status of decommissioning funding for Pilgrim. The report states that the minimum amount (December 2018 dollars) required to demonstrate reasonable assurance of funds for decommissioning, as required by 10 CFR 50.75(c), is $633,267,558.

The HDI analysis in the November 16, 2018, revised PSDAR, projects the total radiological decommissioning cost of Pilgrim to be approximately $592,553,000 in 2018 dollars. The request for exemption from 10 CFR 50.82(a)(8)(i)(A) relies on the estimated costs for radiological decommissioning, including ISFSI decommissioning costs, as well as for spent fuel management and site restoration provided in the revised PSDAR.

Request for Additional Information

1. As identified in the NRC regulations and guidance documents described above, the estimated radiological decommissioning costs, consistent with the definition in 10 CFR 50.2, may be more, but not less, than the amount specified in 10 CFR 50.75(c).

   In the November 16, 2018, license transfer application, the Applicants state the following:

   > The required [DTF] value at closing exceeds the minimum financial assurance required by 10 CFR 50.75(b) and the site-specific estimate of the radiological decommissioning cost, providing sufficient confidence that decommissioning can be achieved without the need for additional financial assurance. Further, a cash-flow analysis based on the site-specific estimate demonstrates that the funds in the [DTF] at closing will be sufficient to fund all radiological decommissioning costs, spent fuel management costs, and site restoration costs through the expected license termination date, and thus demonstrates Holtec Pilgrim's financial qualifications.

   However, there is no comparison in the application between the estimated radiological decommissioning costs of $592,553,000 and the 10 CFR 50.75(c) minimum amount of $633,267,558, as reported by ENOI in its March 28, 2019, decommissioning funding status report.

   Based on the requirements and guidance cited above, please justify using a total radiological decommissioning cost estimate value, consistent with the definition in 10 CFR 50.2, that is less than the minimum amount calculated using 10 CFR 50.75(c) in support of the license transfer application and the exemption request.

2. Using the 10 CFR 50.75(c) minimum amount for radiological decommissioning costs, please provide an updated, revised decommissioning cash flow analysis to support the license transfer application and exemption request.

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HOLTEC DECOMMISSIONING INTERNATIONAL

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July 29, 2019 10 CFR 50.82

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Pilgrim Nuclear Power Station
Renewed Facility Operating License No. DPR-35
NRC Docket Nos. 50-293 and 72-1044

Subject: Response to NRC Request for Additional Information

References:

[1] Letter from A. Christopher Bakken III, (Entergy Nuclear Operations, Inc) to U.S. Nuclear Regulatory Commission - Application for Order Consenting to Direct and Indirect Transfers of Control of Licenses and Approving Conforming License Amendment; and Request for Exemption from 10 CFR 50.82(a)(8)(i)(A) for Pilgrim Nuclear Power Station, dated November 16, 2018 (ADAMS Accession No. ML18320A031).

[2] Letter from Pamela B. Cowan, (Holtec Decommissioning International) to U.S. Nuclear Regulatory Commission – Notification of Revised Post Shutdown Decommissioning Activities Report and Revised Site-Specific Decommissioning Cost Estimate for Pilgrim Nuclear Power Station, dated November 16, 2018 (ADAMS Accession No. ML18320A040).

[3] Email from Scott P. Wall, (U.S. Nuclear Regulatory Commission) to Philip Couture (Entergy Nuclear Operations, Inc)—RAI-PFPB-1—Pilgrim—Application for Order Consenting to Direct and Indirect Transfers of Control of Licenses and Approving Conforming License Amendment, dated July 26, 2019 (ADAMS Accession No. ML19207B366).

Please find attached the "Response to NRC Request for Additional Information (RAI) Regarding the Request for Direct and Indirect Pilgrim License Transfers, RAI-PFPB-1 and -2" prepared and submitted herein by Holtec Decommissioning International, LLC (HDI).

By letter dated November 16, 2018 (Reference 1), as supplemented by letter dated November 16, 2018 (Reference 2), Entergy Nuclear Operations, Inc. (ENOI), on behalf of itself and Entergy Nuclear Generation Company (ENGC) (to be known as Holtec Pilgrim, LLC), Holtec International (Holtec), and Holtec Decommissioning International, LLC (HDI) (together, "Applicants"), requested that the U.S. Nuclear Regulatory Commission (NRC) consent to: (1) the indirect transfer of control of the Renewed Facility Operating License No. DPR-35 for the Pilgrim Nuclear Power Station (Pilgrim), as well as the general license for the Pilgrim Independent Spent Fuel Storage Installation (ISFSI) (collectively the "Licenses"), to Holtec; and (2) the direct transfer of ENOI's operating authority (i.e., its authority to

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conduct licensed activities at Pilgrim) to HDI. In addition, the Applicants requested that the NRC approve a conforming administrative amendment to the Licenses to reflect the proposed direct transfer of the Licenses from ENOI to HDI; a planned name change for ENGC from ENGC to Holtec Pilgrim, LLC; and deletion of certain license conditions to reflect satisfaction and termination of all ENGC obligations after the license transfer and equity sale. In addition, HDI submitted an exemption request, as an enclosure to the letter dated November 16, 2018, to allow HDI to use a portion of the nuclear decommissioning trust for spent fuel management and site restoration costs.

In Reference 3, The NRC provided ENOI with a request for additional information. The HDI response to this RAI is provided in the Enclosure to this letter.

This letter contains no new regulatory commitments.

In the event that the NRC has any questions about the transactions described in this letter or needs to obtain any additional information, please contact the undersigned at 724-493-1833 or a.sterdis@holtec.com.

I declare under penalty of perjury that the foregoing is true and correct. Executed on July 29, 2019.

Respectfully,

Andrea L. Sterdis

Andrea L. Sterdis
Vice President Regulatory and Environmental Affairs
Holtec Decommissioning International, LLC

Enclosure: Response to NRC Request for Additional Information (RAI) Regarding the Request for Direct and Indirect Pilgrim License Transfers, RAI-PFPB-1 and -2

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cc (w/Enclosure):

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NRC Senior Resident Inspector
Pilgrim Nuclear Power Station

Enclosure

Pilgrim Nuclear Power Station
HDI Response to U.S. NRC Requests for Additional Information (RAI)-PFPB-1 and -2 Regarding the Request for Direct and Indirect Pilgrim License Transfers

Following are the references used in this response:

[1] Letter from A. Christopher Bakken III, (Entergy Nuclear Operations, Inc) to U.S. Nuclear Regulatory Commission - Application for Order Consenting to Direct and Indirect Transfers of Control of Licenses and Approving Conforming License Amendment; and Request for Exemption from 10 CFR 50.82(a)(8)(i)(A) for Pilgrim Nuclear Power Station, dated November 16, 2018 (ADAMS Accession No. ML18320A031).

[2] Letter from Pamela B. Cowan, (Holtec Decommissioning International) to U.S. Nuclear Regulatory Commission – Notification of Revised Post Shutdown Decommissioning Activities Report and Revised Site-Specific Decommissioning Cost Estimate for Pilgrim Nuclear Power Station, dated November 16, 2018 (ADAMS Accession No. ML18320A040).

[3] Letter from Brian R. Sullivan, (Entergy Nuclear Operations, Inc) to U.S. Nuclear Regulatory Commission – Certifications of Permanent Cessation of Power Operations and Permanent Removal of Fuel from the Reactor Vessel, dated June 10, 2019 (ADAMS Accession No. ML19161A033).

[4] Letter from Mandy K. Halter, (Entergy Nuclear Operations, Inc) to U.S. Nuclear Regulatory Commission - Decommissioning Funding Status Report per 10 CFR §50.75(f)(1) and 10 CFR 50.82(a)(8)(v) -- Entergy Nuclear Operations, Inc. dated March 28, 2019 (ADAMS Accession No. ML19087A318).

[5] Email from Scott P. Wall, (U.S. Nuclear Regulatory Commission) to Philip Couture (Entergy Nuclear Operations, Inc)—RAI-PFPB-1—Pilgrim—Application for Order Consenting to Direct and Indirect Transfers of Control of Licenses and Approving Conforming License Amendment, dated July 26, 2019 (ADAMS Accession No. ML19207B366).

RAI PFPB-1:

As identified in the NRC regulations and guidance documents described above, the estimated radiological decommissioning costs, consistent with the definition in 10 CFR 50.2, may be more, but not less, than the amount specified in 10 CFR 50.75(c).

In the November 16, 2018, license transfer application, the Applicants state the following:

> The required [DTF] value at closing exceeds the minimum financial assurance required by 10 CFR 50.75(b) and the site-specific estimate of the radiological decommissioning cost, providing sufficient confidence that decommissioning can be achieved without the need for additional financial assurance. Further, a cash-flow analysis based on the site-specific estimate demonstrates that the funds in the [DTF] at closing will be sufficient to fund all radiological decommissioning costs, spent fuel management costs, and site restoration costs through the expected license termination date, and thus demonstrates Holtec Pilgrim's financial qualifications.

However, there is no comparison in the application between the estimated radiological decommissioning costs of $592,553,000 and the 10 CFR 50.75(c) minimum amount of $633,267,558, as reported by ENOI in its March 28, 2019, decommissioning funding status report.

Based on the requirements and guidance cited above, please justify using a total radiological decommissioning cost estimate value, consistent with the definition in 10 CFR 50.2, that is less than the minimum amount calculated using 10 CFR 50.75(c) in support of the license transfer application and the exemption request.

Response:

The information provided by the Applicants in support of the License Transfer Application and HDI's exemption request complies with applicable NRC regulations and is consistent with applicable NRC guidance. NRC regulations at 10 CFR 50.75(b) and related guidance in RG 1.202 and RG 1.159 apply to certifications of decommissioning funding amounts that licensees and applicants of *operating* reactors are required to make during the earlier stages of a plant's operating life. 10 CFR 50.75(b)(1) requires an applicant for an operating license to provide a certification that financial assurance for decommissioning has or will be provided in an amount that may not be less than the minimum financial assurance amount calculated pursuant to the generic formula in 10 CFR 50.75(c). The minimum financial assurance amount does not, however, represent the actual cost of decommissioning. Rather, it is "a reference level established to assure that licensees demonstrate adequate financial responsibility that the bulk of the funds necessary for a safe decommissioning are being considered and planned for *early in facility life*." General Requirements for Decommissioning Nuclear Facilities, 53 Fed. Reg. 24,018, 24,030 (June 27, 1988) (emphasis added). As noted in the guidance, the certification required by 10 CFR 50.75(b) was intended to be a "first step" in providing reasonable assurance of decommissioning funds, followed by the submittal of a preliminary decommissioning cost estimate, a site-specific decommissioning cost estimate pursuant to 10 CFR 50.82, and then an updated site-specific decommissioning cost estimate as part of a license termination plan. RG 1.159, Rev. 2 at 5-7. The guidance further states, "The purpose of the decommissioning report, required under 10 CFR 50.33(k) and described in 10 CFR 50.75(b) and (c), is to provide reasonable assurance that licensees have a viable plan to accumulate funds in the certification amount, adjusted for inflation, by the projected time of permanent cessation of operations." *Id.* at 8. Accordingly, the requirements in 10 CFR 50.75(b) related to the submittal of a decommissioning report and certification of decommissioning financial assurance were intended to apply in the earlier stages of plant operations, and not after permanent cessation of operations.

Furthermore, even if 10 CFR 50.75(b) were to be applied to plants that had entered decommissioning, the regulation does not require that a site-specific cost estimate for decommissioning prepared pursuant to 10 CFR 50.82(a)(8)(iii) must be greater than the 10 CFR 50.75(c) formula amount. In that regard, RG 1.202 recognizes that the certification amount required by 10 CFR 50.75(b)(1) may be based on "a site-specific cost estimate, which may be more (but not less) than the amount specified in 10 CFR 50.75(b)(1) *when a higher funding level than 10 CFR 50.75(c) is desired*." RG 1.202 at 1.202-4 (emphasis added). Significantly, however, the guidance clarifies that the site-specific cost estimate used for the certification "is *not the same site-specific cost estimate required by 10 CFR 50.82(a)(8)(iii)*." *Id*. (emphasis added). Thus, there is no requirement that a site-specific cost estimate submitted pursuant to 10 CFR 50.82(a)(8)(iii) must equal or exceed the minimum formula amount.

Nor is there any provision in the NRC rules that requires a licensee to maintain financial assurance equaling or exceeding the generic formula amount after a plant permanently ceases operation. Instead, at that

juncture, the requirements in 10 CFR 50.82 apply.[1] 10 CFR 50.82(a)(4)(i) requires a site-specific cost estimate to be submitted as part of the PSDAR but contains no requirement that this estimate equal or exceed the formula amount. Indeed, the annual reporting requirement in 10 CFR 50.82(a)(8)(v)-(vi) clearly shows a licensee of a permanently shut down plant is not required to maintain funding assurance equaling or exceeding the generic formula amount. As reflected in those provisions, after submitting its site-specific decommissioning cost estimate, a licensee of a plant that has permanently ceased operation must annually report and provide assurance for the estimated cost to complete decommissioning. This estimate declines as decommissioning proceeds.

In November 2018, ENOI and Holtec jointly requested a transfer of the Pilgrim licenses, noting that "the transfer will occur following docketing of ENOI's certifications of permanent removal of fuel from the reactor vessel" (Reference 1). Because the application does not request transfer of the licenses until Pilgrim is permanently defueled, HDI submitted a revised site-specific decommissioning cost estimate (DCE) pursuant to 10 CFR 50.82(a)(7) in support of its demonstration that there would be reasonable assurance of decommissioning funding upon license transfer (Reference 2). On June 10, 2019, ENOI certified to the NRC that power operations permanently ceased at Pilgrim on May 31, 2019, and that it had permanently removed all fuel from the Pilgrim reactor on June 9, 2019 (Reference 3). Pursuant to 10 CFR 50.82(a)(2), the Pilgrim 10 CFR Part 50 license no longer authorizes operation of the reactor or emplacement or retention of fuel into the reactor vessel. Accordingly, the requirements in 10 CFR 50.82, rather than 10 CFR 50.75(b), apply to Pilgrim effective May 31, 2019 and will continue to apply to Pilgrim after the proposed license transfer occurs.

Once a site-specific decommissioning cost estimate pursuant to 10 CFR 50.82(a)(8)(iii) has been submitted, NRC guidance suggests that NRC reviewers should compare the site-specific cost estimate against the minimum financial assurance amount to assist the staff in evaluating the reasonableness of the cost estimate. *See, e.g.*, RG 1.202 at 1.202-9; NUREG-1713 at 21. NUREG-1713 (at 21) states:

> The [NRC] reviewer will use the following process to determine that the submitted [site-specific DCE] considers, in adequate detail, all major site-specific factors that could affect the cost to decommission, and to ensure that the [site-specific DCE] appears reasonable.
>
> The [NRC] reviewer should compare the [site-specific DCE] with the minimum decommissioning financial assurance requirement amount derived per the algorithm discussed in [10 CFR 50.75(c)]. If the [site-specific DCE] is less than the amount derived from the algorithm in 10 CFR 50.75(c) and adequate justification is not provided, [the NRC] will inform the licensee in writing of additional information needed to resolve the deficiency.

Thus, the guidance indicates that a comparison between the 10 CFR 50.82(a)(8)(iii) site-specific cost estimate and the minimum financial assurance amount is intended to be just one of many factors that the staff should consider as it assesses a licensee's site-specific cost estimate. If a site-specific

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[1] *See, e.g.*, SECY-18-0078, Summary of Staff Review and Findings of the 2017 Decommissioning Funding Status Reports from Operating and Decommissioning Power Reactor Licensees (Aug. 6, 2018) at 2 ("Pursuant to NRC regulations at 10 CFR 50.75(f)(1) (*for operating power reactors*) and 10 CFR 50.82(a)(8)(v)–(vi) (for power reactors in decommissioning), licensees are required to submit [decommissioning funding status] reports to the NRC. . . . *For operating reactors*, in accordance with 10 CFR 50.75(f)(1), the DFS reports must include: (1) the amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and 10 CFR 50.75(c) . . . " (emphasis added)).

decommissioning cost estimate is less than the formula amount, and adequate justification is not provided, then the staff should obtain additional information from the licensee.

The justification for using a total radiological decommissioning cost estimate value, consistent with the definition in 10 CFR 50.2, that is less than the minimum amount calculated using 10 CFR 50.75(c) in support of the license transfer application and the exemption request is that HDI's site-specific DCE reflects an actual, detailed estimate of decommissioning costs. As the Commission explained when it promulgated 10 CFR 50.75, the formula amount represented a "first step" in establishing "a general level of adequate financial responsibility early in life." 53 Fed. Reg. at 24,030. By contrast, HDI's site-specific cost estimate of the going forward costs that HDI expects to incur after license transfer is based on Pilgrim-specific plant data and historical information, actual site conditions, regulatory requirements applicable to Pilgrim, and actual pricing information, and is therefore significantly more reliable and precise than the formula amount, which is based on generic inputs. For example, with respect to waste disposal costs, which represent a significant portion of the estimated radiological decommissioning costs, the Application states that "[d]isposal facilities were selected and pricing was confirmed." In addition, as stated in the Application and DCE, HDI reviewed the estimates of costs associated with license termination in NUREG/CR-6174, Revised Analyses of Decommissioning for the Reference Boiling Water Reactor Power Station, in order to evaluate the reasonableness of the decommissioning estimate, benchmarked the estimated radiological decommissioning costs against nine comparable decommissioning projects, and compared the decommissioning cost estimate to costs from similar activities at seven boiling water reactors. The DCE includes considerable additional information supporting the reliability of the cost estimates. Therefore, ample justification for why HDI's site-specific DCE is less than the generic minimum formula amount has been provided.

<u>RAI PFPB-2:</u>

Using the 10 CFR 50.75(c) minimum amount for radiological decommissioning costs, please provide an updated, revised decommissioning cash flow analysis to support the license transfer application and exemption request.

<u>Response:</u>

As an initial matter, as noted above in the response to RAI 1, the 10 CFR 50.75(c) minimum financial assurance amount is "a reference level established to assure that licensees demonstrate adequate financial responsibility that the bulk of the funds necessary for a safe decommissioning are being considered and planned for early in facility life." 53 Fed. Reg. at 24,030. It is not a decommissioning cost estimate. Thus, a cash flow analysis that uses the 10 CFR 50.75(c) minimum amount as the total radiological decommissioning cost does not reflect HDI's *actual* projected cash flows for the decommissioning work it plans to perform at Pilgrim.

HDI's projected cash flow analysis was provided in Enclosure 1 to the License Transfer Application (Reference 1) and is based on HDI's site-specific DCE (Reference 2) and HDI's schedule of planned decommissioning activities. The Applicants respectfully submit that the actual Cash Flow Analysis table provided in Reference 1 should form the basis for the NRC staff's review of the Application and exemption request. As reflected in that table, HDI estimated a total of $592,553,322 for completing radiological decommissioning activities, which are referred to as "license termination" activities in HDI's site-specific DCE and Cash Flow Analysis table.[2] This amount reflects HDI's detailed estimate of the going forward license termination costs that HDI expects to incur after license transfer, based on Pilgrim-specific plant

[2] The dollar values in the Cash Flow Analysis table provided in Reference 1 reflect rounding.

data and historical information, actual site conditions, regulatory requirements applicable to Pilgrim, actual pricing information, as well as HDI's schedule of planned decommissioning activities and projected annual expenditures based on the timing of those activities, which HDI plans to initiate promptly upon license transfer and purchase.

As required by 10 CFR 50.75(f)(1), ENOI submitted the annual report on the status of the Pilgrim Nuclear Power Station decommissioning trust fund to the NRC on March 29, 2019 (Reference 4). In this submittal, ENOI provided the escalated Minimum Funding Amount (MFA) for the Pilgrim Station using the 10 CFR 50.75(c)(2) Escalation Factor Formula. The formula takes into account the reactor type and power level, with generic adjustment factors for regional labor and energy costs taken from U.S. Department of Labor data and for waste burial costs taken from NRC guidance document NUREG-1307, "Report on Waste Burial Charges." Using the generic formula in 10 CFR 50.75(c), ENOI calculated the MFA for Pilgrim for year ending December 31, 2018 to be $633,267,558, which is $40,714,236 more than HDI's detailed site-specific estimate of license termination costs submitted on November 16, 2018 (References 1 and 2).

Although the generic MFA calculation does not take into account any Pilgrim-specific data, cost estimates, assumptions, schedule for planned decommissioning activities, or timing of expenditures, HDI has developed a cash flow analysis with license termination costs adjusted to total the MFA of $633,267,558 (see Attachment 1 to this response). To do this, HDI distributed the difference between the MFA submitted by ENOI on March 29, 2019 and the amount of HDI's site-specific license termination cost estimate ($40,714,236) equally among the 11 years in which HDI expects to perform license termination activities. This resulted in an increase in each of the annual amounts provided in the License Termination Cost column of the Cash Flow Analysis table provided in Reference 1 of $3,701,294 ($40,714,236/11 years = $3,701,294 per year). For example, for 2019, HDI increased the annual License Termination Cost value from $84,927,000 to $88,628,788 ($84,927,000 + $3,701,294 = $88,628,788). A similar adjustment was performed for all other years in which HDI expects to perform license termination activities (i.e., 2020-2025 and 2060-2063).

In addition, the cash flow analysis in Attachment 1 incorporates the following assumptions:

1) The costs for a specific year are conservatively assumed to be withdrawn on January 1 of that year.

2) The earnings for a specific year are conservatively based on the NDT fund value on December 31 of that year.

3) The earnings utilize a 2% real rate of return on investment, consistent with NRC regulations. The Cash Flow Analysis table provided in Reference 1 provided the annual earnings Net of Taxes and therefore resulted in a lower rate.

The attached table demonstrates that using the MFA as the total license termination cost estimate results in a remaining NDT balance of $11,595,232 at the time the Pilgrim license is terminated, after all license termination, spent fuel management, and site restoration activities have been completed. Accordingly, even if the generic MFA was used in place of HDI's site-specific cost estimate for license termination activities, HDI has demonstrated that the NDT provides reasonable assurance of the availability of decommissioning funding, and therefore, that Holtec Pilgrim and HDI are financially qualified to hold the Pilgrim licenses.

Enclosure

Pilgrim Nuclear Power Station
HDI Response to U.S. NRC Requests for Additional Information (RAI)-PFPB-1 and -2 Regarding the Request for Direct and Indirect Pilgrim License Transfers

Attachment 1

HDI Decommissioning Cost Estimate (DCE) Adjusted to include Additional License Termination Costs to Compare to 2018 Formula Amount

Pilgrim Nuclear Power Station –
HDI DECOMMISSIONING COST ESTIMATE (DCE) Adjusted to Include Additional License Termination Costs to Compare to 2018 Formula Amount
Annual Cash Flow in 2018 Dollars
No DOE Reimbursement of Spent Fuel Management Costs

Year	HDI 10 CFR 50.75 License Termination Cost Estimate	Adjustment $$ to compare to 2018 formula	License Termination Cost Estimate Adj to compare to 2018 formula	Spent Fuel Management Cost (unchanged)	Site Restoration Cost (unchanged)	Total Estimated Costs Adj to compare to 2018 formula	Beginning of Year NDT Balance[1]	Withdrawals Adj to compare to 2018 formula	NDT Earnings[2]	Year Ending NDT Balance Adj to compare to 2018 formula
2019	84,927,494	3,701,294	88,628,788	53,919,755	17,619	142,566,162	1,030,000,000	-142,566,162	7,395,282	894,829,120
2020	79,292,448	3,701,294	82,993,743	84,905,227	27,597	167,926,566	894,829,120	-167,926,566	14,538,051	741,440,604
2021	46,758,773	3,701,294	50,460,067	82,500,059	636,985	133,597,110	741,440,604	-133,597,110	12,156,870	620,000,364
2022	103,197,395	3,701,294	106,898,690	3,331,593	23,629,849	133,860,131	620,000,364	-133,860,131	9,722,805	495,863,038
2023	167,453,076	3,701,294	171,154,370	3,135,304	1,699,521	175,989,195	495,863,038	-175,989,195	6,397,477	326,271,320
2024	95,693,887	3,701,294	99,395,182	3,225,310	9,235,554	111,856,046	326,271,320	-111,856,046	4,288,305	218,703,579
2025	1,309,633	3,701,294	5,010,927	6,306,278	4,126,523	15,443,727	218,703,579	-15,443,727	4,065,197	207,325,049
2026	0		0	5,952,309	0	5,952,309	207,325,049	-5,952,309	4,027,455	205,400,195
2027	0		0	5,938,720	0	5,938,720	205,400,195	-5,938,720	3,989,229	203,450,704
2028	0		0	5,952,309	0	5,952,309	203,450,704	-5,952,309	3,949,968	201,448,363
2029	0		0	5,952,309	0	5,952,309	201,448,363	-5,952,309	3,909,921	199,405,975
2030	0		0	7,211,549	0	7,211,549	199,405,975	-7,211,549	3,843,889	196,038,314
2031	0		0	7,211,549	0	7,211,549	196,038,314	-7,211,549	3,776,535	192,603,301
2032	0		0	7,211,549	0	7,211,549	192,603,301	-7,211,549	3,707,835	189,099,587
2033	0		0	7,211,549	0	7,211,549	189,099,587	-7,211,549	3,637,761	185,525,799
2034	0		0	7,192,982	0	7,192,982	185,525,799	-7,192,982	3,566,656	181,899,472
2035	0		0	7,211,549	0	7,211,549	181,899,472	-7,211,549	3,493,758	178,181,682
2036	0		0	7,230,115	0	7,230,115	178,181,682	-7,230,115	3,419,031	174,370,598
2037	0		0	7,211,549	0	7,211,549	174,370,598	-7,211,549	3,343,181	170,502,230
2038	0		0	7,192,982	0	7,192,982	170,502,230	-7,192,982	3,266,185	166,575,432
2039	0		0	7,211,549	0	7,211,549	166,575,432	-7,211,549	3,187,278	162,551,161
2040	0		0	7,211,549	0	7,211,549	162,551,161	-7,211,549	3,106,792	158,446,404
2041	0		0	7,211,549	0	7,211,549	158,446,404	-7,211,549	3,024,697	154,259,553
2042	0		0	7,211,549	0	7,211,549	154,259,553	-7,211,549	2,940,960	149,988,964

[1] The 2019 Beginning of Year NDT balance reflects the fund value post-closure of the equity sale. The value used does not include deductions for ENOI pre-closure costs. The 2019 costs include HDI estimated pre-closure and post closure costs.

[2] NDT earnings reflect an assumed 2% Real Rate of Return (RRR)

Pilgrim Nuclear Power Station –
HDI DECOMMISSIONING COST ESTIMATE (DCE) Adjusted to Include Additional License Termination Costs to Compare to 2018 Formula Amount

Annual Cash Flow in 2018 Dollars
No DOE Reimbursement of Spent Fuel Management Costs

Year	HDI 10 CFR 50.75 License Termination Cost Estimate	Adjustment $$ to compare to 2018 formula	License Termination Cost Estimate Adj to compare to 2018 formula	Spent Fuel Management Cost (unchanged)	Site Restoration Cost (unchanged)	Total Estimated Costs Adj to compare to 2018 formula	Beginning of Year NDT Balance[1]	Withdrawals Adj to compare to 2018 formula	NDT Earnings[2]	Year Ending NDT Balance Adj to compare to 2018 formula
2043	0		0	7,211,549	0	7,211,549	149,988,964	-7,211,549	2,855,548	145,632,963
2044	0		0	7,211,549	0	7,211,549	145,632,963	-7,211,549	2,768,428	141,189,842
2045	0		0	7,192,982	0	7,192,982	141,189,842	-7,192,982	2,679,937	136,676,797
2046	0		0	7,211,549	0	7,211,549	136,676,797	-7,211,549	2,589,305	132,054,553
2047	0		0	7,211,549	0	7,211,549	132,054,553	-7,211,549	2,496,860	127,339,864
2048	0		0	7,230,115	0	7,230,115	127,339,864	-7,230,115	2,402,195	122,511,944
2049	0		0	7,192,982	0	7,192,982	122,511,944	-7,192,982	2,306,379	117,625,341
2050	0		0	7,211,549	0	7,211,549	117,625,341	-7,211,549	2,208,276	112,622,068
2051	0		0	7,192,982	0	7,192,982	112,622,068	-7,192,982	2,108,582	107,537,667
2052	0		0	7,230,115	0	7,230,115	107,537,667	-7,230,115	2,006,151	102,313,703
2053	0		0	7,211,549	0	7,211,549	102,313,703	-7,211,549	1,902,043	97,004,197
2054	0		0	7,211,549	0	7,211,549	97,004,197	-7,211,549	1,795,853	91,588,501
2055	0		0	7,192,982	0	7,192,982	91,588,501	-7,192,982	1,687,910	86,083,429
2056	0		0	7,211,549	0	7,211,549	86,083,429	-7,211,549	1,577,438	80,449,317
2057	0		0	7,211,549	0	7,211,549	80,449,317	-7,211,549	1,464,755	74,702,524
2058	0		0	7,211,549	0	7,211,549	74,702,524	-7,211,549	1,349,819	68,840,794
2059	0		0	7,211,549	0	7,211,549	68,840,794	-7,211,549	1,232,585	62,861,830
2060	4,295,660	3,701,294	7,996,954	7,211,549	0	15,208,503	62,861,830	-15,208,503	953,067	48,606,394
2061	4,375,107	3,701,294	8,076,401	7,211,549	0	15,287,950	48,606,394	-15,287,950	666,369	33,984,813
2062	4,357,793	3,701,294	8,059,087	7,192,982	0	15,252,069	33,984,813	-15,252,069	374,655	19,107,399
2063	892,056	3,701,294	4,593,351	2,440,549	705,625	7,739,524	19,107,399	-7,739,524	227,357	11,595,232
Total[13]	592,553,322	40,714,236	633,267,558	501,466,571	40,079,271	1,174,813,400		(1,174,813,400)	156,408,632	

[1] The 2019 Beginning of Year NDT balance reflects the fund value post-closure of the equity sale. The value used does not include deductions for ENOI pre-closure costs. The 2019 costs include HDI estimated pre-closure and post closure costs.

[2] NDT earnings reflect an assumed 2% Real Rate of Return (RRR)

[3] Columns may not add due to rounding

QUESTIONS AND ANSWERS ON DECOMMISSIONING FINANCIAL ASSURANCE

OPTIONS TO EVALUATE REQUESTS TO USE DISCOUNTED PARENT COMPANY GUARANTEES TO ASSURE FUNDING OF DECOMMISSIONING COSTS FOR POWER REACTORS

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Questions and Answers on Decommissioning Financial Assurance

1. Why does the NRC require reactor licensees to provide financial assurance?

The NRC has a statutory duty to protect the public health and safety and the environment. The requirements for financial assurance were issued because inadequate or untimely consideration of decommissioning, specifically in the areas of planning and financial assurance, could result in significant adverse health, safety and environmental impacts. The requirements are based on extensive studies of the technology, safety, and costs of decommissioning (53 FR 24018). The NRC determined that there are significant radiation hazards associated with non-decommissioned nuclear reactors. The NRC also determined that the public health and safety can best be protected if its regulations require licensees to use methods which provide reasonable assurance that, at the time of termination of operations, adequate funds are available so that decommissioning can be carried out in a safe and timely manner and that lack of funds does not result in delays that may cause potential health and safety problems (53 FR 24018, 24033). The purpose of financial assurance is to provide a second line of defense, if the financial operations of the licensee are insufficient, by themselves, to ensure that sufficient funds are available to carry out decommissioning (63 FR 50465, 50473).

2. Can a licensee or a parent company meet the financial assurance requirements by submitting its financial statement or indicators of its net worth?

No. In *United States v. Ecko Housewares*, the court held that the defendant could not provide financial assurance by submitting a financial statement or other indicators of its net worth:

> In contrast, argues Ekco, its violations merely involved a failure to provide the EPA with financial documentation. Ekco's assessment of the relative seriousness of a violation of the financial responsibility regulations is questionable. These regulations are not mere paperwork requirements, and a party cannot comply by submitting a financial statement or other indicators of its net worth. The purpose of these regulations is to ensure that adequate funds are secured (through, e.g., a letter of credit, guarantee or liability policy) in the present to meet the future financial needs for closing a hazardous waste site and satisfying any third-party claims that might arise therefrom. A present violation of these regulations may significantly impair the ability to close and remediate the site when needed and to protect third parties from harm. This risk of future harm posed by a hazardous waste facility such as that owned by Ekco, found by the district court to present serious risks to human health and the environment, is no less important a consideration than the risk of present harm caused by activities causing contamination. *United States v. Ekco Housewares, Inc.*, 62 F 3d 806, 817 (6th Cir. 1995)

The NRC's financial assurance regulations are modeled on the EPA financial responsibility regulations for hazardous waste operators. (53 FR 24018, 24036) The *Ecko* case provides insight into the appropriate application of financial assurance requirements.

3. A number of parent companies have assets well in excess of the cost of decommissioning. Why doesn't the NRC count those assets as part of financial assurance?

A parent company is not an NRC licensee. The NRC does not have the authority to require a parent company to pay for the decommissioning expenses of its subsidiary-licensee, except to the extent the parent may voluntarily provide a PCG. In addition, the principle that a parent company has no liability for the acts of its subsidiary is recognized by the United States Supreme Court:

> It is a general principle of corporate law deeply "ingrained in our economic and legal systems" that a parent corporation (so-called because of control through ownership of another corporation's stock) is not liable for the acts of its subsidiaries. *United States v. Bestfoods*, 524 U.S. 51, 61 (1998)

In view of the absence of authority to compel a parent to pay for the decommissioning costs of its subsidiary-licensee, other than a PCG, if available, there is no assurance that the parent's assets will be used to pay for the subsidiary-licensee's decommissioning costs. Due to that limitation, the licensee must provide assurance that funds will be available using the methods of 10 CFR 50.75.

4. What is a parent company guarantee (PCG)?

The PCG is defined in Appendix A to 10 CFR Part 30. It is a guarantee between the parent and its subsidiary-licensee stating that the parent company will pay a specific amount of the decommissioning costs of its subsidiary-licensee, if the subsidiary-licensee fails to meet its decommissioning obligation. The parent must pass a financial test, which, among other items, requires the parent to possess tangible net worth, assets each worth 6 times the amount guaranteed, and an investment grade credit rating.

The PCG is a non-cash, unsecured promise to pay over funds to the licensee, or a standby trust set up for decommissioning costs, in the event the licensee fails to meet its decommissioning obligation. The parent company has no obligation to pay until after the licensee fails, and no obligation to pay more than the PCG amount. The PCG has no requirements to set aside funds or to provide a security interest or collateral to assure performance of the obligation to pay over the funds when demanded. The PCG places no restrictions on the parent regarding how its uses it assets for any purpose.

The PCG cannot be used to require the parent to pay during operations, since no decommissioning activates are required during that time. After permanent shutdown, the PCG does not compel payment until after the licensee fails to perform its decommissioning activities. The licensee has 60 years to complete decommissioning, which could delay payment on the PCG for 60 years after permanent shutdown.

5. What is a discounted PCG?

A discounted PCG guarantees a discounted amount of the decommissioning cost. The discount varies depending on how many years remain before decommissioning starts. A nuclear industry representative suggested using a discount rate of 2% per year. The discount is computed using a non-linear formula, so doubling the years does not double the discount. The table below shows the discount for a number of time periods. For example, assuming decommissioning starts in 20 years, from the DFA requirement would be 33%. Therefore, the discounted PCG would guarantee 67% of the DFA requirement. The table is based on completing decommissioning in one year. In reality, decommissioning takes several years, so the discount in an actual case will be different.

Discount from DFA Requirement @ 2% per Year		
20 Years	40 Years	60 Years
33%	55%	70%

6. What is net present value (NPV)?

The following description is taken from Wikipedia.com. In finance, the NPV of a time series of cash flows, both incoming and outgoing, is defined as the sum of the present values (PVs) of the individual cash flows of the same entity. In the case when all future cash flows are incoming (such as coupons and principal of a bond) and the only outflow of cash is the purchase price, the NPV is simply the PV of future cash flows minus the purchase price (which is its own PV). NPV is a central tool in discounted cash flow (DCF) analysis, and is a standard method for using the time value of money to appraise long-term projects. Used for capital budgeting, and widely throughout economics, finance, and accounting, it measures the excess or shortfall of cash flows, in present value terms, once financing charges are met. The NPV of a sequence of cash flows takes as input the cash flows and a discount rate or discount curve and outputs a price.

The equation for the NPV of a series of cash flows is:

$$NPV = \sum_{t=0}^{t} \frac{R_t}{(1+i)^t}$$

where
t = the time of the cash flow
i = the discount rate (the rate of return that could be earned on an investment in the financial markets with similar risk.), or the opportunity cost of capital
R_t = the net cash flow (the amount of cash, inflow minus outflow) at time t.

7. What is NPV in non-technical terms?

An analogy to a home mortgage may make the concept clearer. The balance on the mortgage is the NPV of the all the remaining payments.

Another example is saving for a child's college education. NPV is the amount of money you need to invest today in order to have enough money to pay for college when the child starts college.

8. What is the earnings credit that can be used for decommissioning financial assurance?

The earnings credit recognizes that funds in a nuclear decommissioning trust (NDT) may produce earnings that can be used to pay for decommissioning costs. Reactor licensees are allowed to take a credit for the anticipated future earnings. The credit may be added to their NDT balance to satisfy the NRC's regulations to provide financial assurance for decommissioning costs.

The equation for calculating the earnings credit is:

$$earnings\ credit = NDT_{balance}\{(1+\ r)^t - 1\}$$

where
$NDT_{balance}$ = the balance in the NDT
r = interest rate
t = time.

9. What's the difference between NPV and an earnings credit?

The two are used for different purposes. NPV is a decision making tool used for capital investment analysis and other decision making purposes. The earnings credit is a cost-saving measure authorized for reactor licensees to reduce the burden of providing financial assurance for decommissioning costs.

10. How are NPV and the earnings credit similar?

Both NPV and the earnings credit can be used to determine what balance is needed in the NDT to satisfy the decommissioning financial assurance (DFA) requirements of the NRC's rules.

11. How does NPV relate to discounting?

The NPV equation produces a result that is less than the future cash flow. For example, the balance on a mortgage is always less than the sum of the remaining payments. As a result, NPV is a discounted amount of the future payments. As applied to DFA, NPV gives a discount to the DFA requirement. For example, if the DFA requirement for a new reactor is

$405 million, the NPV would be $171 million. However, the NRC's rules do not allow a licensee to provide less than the DFA requirement.

12. What is the flaw in the NPV method when applied to discounting the PCG?

The NPV method applies to cash flows. The PCG has no cash, so there is nothing to discount.

13. What is the flaw in the earnings credit method when applied to the PCG?

An earnings credit recognizes that funds in a NDT may produce earnings that can be used to pay for decommissioning costs. However, the PCG has no cash and cannot produce earnings to pay for decommissioning. The value of the PCG is its face amount, and nothing more.

14. The NRC regulations allow an earnings credit on a trust fund balance, isn't that the same thing as a NPV discount of the PCG?

No. An earnings credit specifically applies to the earnings ability of funds held in an account segregated from licensee assets and outside the administrative control of the licensee and its subsidiaries or affiliates. The credit recognizes that funds held in a NDT may produce earnings if wisely invested. NRC rules allow reactor licensees to add the earnings credit to the trust fund balance. However, since the PCG has no funds, it cannot produce earnings, and there is no credit that can be added.

Net present value (NPV) discounting is an investment tool used to decide whether or not to invest in a project. The NRC rejected the use of investment decision making discount rates as a method to determine financial assurance amounts. As stated in the Supplementary Information of the 1998 Decommissioning Rule, calculating contributions to decommissioning funds based on discount rates used in capital investment analysis can result in financial assurance levels that are not adequate to pay for all assured obligations. (63 FR 50465, 50477) In a number of cases where a licensee proposed to use a discounted PCG, the total amount of DFA including the discounted PCG was not adequate to cover the minimum prescribed amount of the regulations.

15. How would a PCG work if it was applied to a home mortgage?

Using an analogy to a home mortgage, the purchase price of the home represents the decommissioning cost estimate, codified in 10 CFR 50.75(c)(1). The interest on the mortgage represents the escalation in the cost estimate, codified in 10 CFR 50.75(c)(2). The homebuyer represents the licensee, and the homebuyer's parent represents the licensee's parent company.

To use a PCG to purchase a home, the homebuyer would arrange to have his parent give him a guarantee stating that if the homebuyer did not pay the purchase price at the end of the 40-year mortgage, then the parent would pay it. The parent would have to pass a financial test showing that he possessed tangible net worth and assets each at least 6 times

the purchase price. The homebuyer would then present the PCG to the bank to get the mortgage. He would not have to make any payments for one year. Each year after that, the parent would have to pass the financial test and increase the PCG amount to cover the purchase price plus unpaid interest. The homebuyer would present the bank with the updated PCG each year and would not have to make any mortgage payments.

However, in the 40th year, when the mortgage comes due, the homeowner can make a choice to extend the repayment period. The PCG has a special property that allows it to be extended for an additional 60 years after the mortgage is due, at the option of the homebuyer. So, when the homebuyer reaches the end of the mortgage period, he can pay up, or continue to keep sending updated PCGs to the bank for the next 60 years and continue to avoid making any mortgage payments. In the 100th year, the PCG would equal the purchase price plus unpaid interest. The homebuyer, or his parent, would then have to pay.

16. How would a discounted PCG work if it was applied to a home mortgage?

It would be the same, except that the PCG would have to guarantee only about 16% of the purchase price to start, by immediately electing to use the option to delay payments until 60 years after the end of the mortgage period. At the end of the 40-year mortgage period, the PCG would grow to about 30% of the purchase price plus the unpaid interest. Similar to the full-value PCG, in the 100th year, the PCG would equal the purchase price plus unpaid interest.

17. What are the pros and cons of using the PCG as financial assurance, from the licensee and parent company point of view?

An advantage comes from delaying the payment for decommissioning, and avoiding a deposit into the trust fund. By doing so, the licensee or parent may earn a greater return by investing the money in a potentially profitable business project. However, a disadvantage for the parent company is accepting some responsibility for decommissioning the reactor facility, up to the amount of the guarantee.

18. What would happen if the NRC allowed the discounted PCG to be used for DFA?

Due to the low cost of the PCGs, parent companies have an incentive to delay or cease payments into the decommissioning trust funds and rely on the PCG as much as possible. The discounted PCG would allow a parent company to use more PCGs to provide DFA for decommissioning. It can lead to a longer delay or earlier cessation of payments to the NDT.

19. If the PCG is so attractive, then why don't more parent companies use them?

Due to their legacy as rate-regulated public utilities, reactor licensees have accumulated large amounts of funds in their NDTs. In most cases, and most of the time, the projected earnings, combined with ratepayer collections where permitted, are adequate to meet the DFA requirements. The need for PCGs occurs only from time-to-time.

PCGs can be useful when a licensee wants to reduce or delay contributions into its NDT. For example, one parent company provided PCGs in the amount of $276 million dollars to meet the NRC DFA requirements for several years until it obtained license renewal for three of its reactor facilities. When license renewal was granted, the additional earnings credit during the extra 20 years of operation allowed the licensee to meet the NRC's regulations without adding funds to its NDT. Another parent company provided $219 million in PCGs to cover market losses in its subsidiary-licensee's NDTs until the NDTs increased in value to meet the NRC requirements. Relatively few licensees carry PCG for long periods of time. However, one applicant for a combined reactor license proposed to use a PCG for the full amount of its DFA requirement, approximately $400 million.

20. Do the cost formulas of 10 CFR 50.75(c) represent the future cost to decommission a nuclear reactor?

No. The NRC formulas represent the cost to decommission today, not in the future. Due to rising costs, the future value of decommissioning will be much larger than the NRC formula calculated today. For example, using the range of cost escalation rates based on NUREG-1307, the increase in cost over a 20-year license renewal period would range from 2.5 to 5.6 times today's estimated cost, not counting costs that are not included in the formula, such as soil contamination. The rates of increase in decommissioning cost are higher than general inflation.

21. Does the minimum amount of financial assurance for decommissioning provide enough money to pay for decommissioning today?

No. The amount listed as the prescribed amount in 10 CFR 50.75 does not represent the actual cost of decommissioning for specific reactors. It is a reference level established to assure that licensees demonstrate adequate financial responsibility that the bulk of the funds necessary for a safe decommissioning are being considered and planned for early in facility life. Setting aside the bulk of the funds during the life of the facility provides adequate assurance that the facility would not become a risk to public health and safety when it is decommissioned. (53 FR 24018, 24030)

22. What assurance is there that rate regulators will provide funds for decommissioning?

Because public utility commissions set a utility's rates such that all reasonable costs of serving the public may be recovered and because NRC requirements concerning termination of a license are a part of the reasonable cost of having operated a reactor, it is reasonable to assume that added costs beyond those in the prescribed amount could be obtained. (53 FR 24018, 24031) In a number of cases where the licensee was a public utility that shut down prematurely, State Public Utility Commissions have authorized hundreds of millions of dollars in additional rate collections to cover the cost of decommissioning.

23. How does a licensee know what is acceptable as a funding method?

The regulations of 10 CFR 50.75 define the acceptable funding methods. Regulatory guides provide guidance on how the funding methods are to be implemented.

24. What are the NRC's criteria for evaluating funding methods? Which criterion is most important?

The NRC has two primary criteria for evaluating funding methods. The first is the degree of assurance, which measures the effectiveness of a funding method to assure that funds for decommissioning will be available when needed. The second criterion is the cost of providing assurance. From the Commission's perspective, assurance is the most important criterion. (50 FR 5600, 5607)

25. How does the NRC define the cost of a funding method?

The cost of a funding method is defined as the incremental revenue requirements that result from using a particular method, other factors being equal. (50 FR 5600, 5608)

26. How does the PCG save money for the licensee and its owner?

The PCG eliminates the financing fees that the licensee would have to pay if it used a third party issuer to obtain a surety or LOC to cover decommissioning costs. It also allows the licensee to delay or cease payments into its nuclear decommissioning (NDT) trust fund, which eliminates a cost each year that the payments are delayed.

27. What is the basis for limiting the earnings credit to no more than a 2 percent annual real rate of return?

The 2 percent real rate of return is based on historical data on returns from U.S. Treasury issues. It represents as close to the "risk-free" return as possible. The long-term real rate of return on the Treasury issues has ranged from 0.6 percent to 2.1 percent per year, although short-term rates have been higher. The NRC stated that the Treasury rates were expected to be achievable on a more consistent basis than the higher interest rates frequently paid on common stocks and corporate bonds. The NRC stated it would have difficulty justifying a higher rate, due to the requirement to provide reasonable assurance. (63 FR 50465, 50476 - 77) However, if a rate regulatory authority authorizes a higher real rate of return for an NRC licensee, the higher rate will normally be accepted.

28. What is the real rate of return?

It is the return on investment after adjusting for cost escalation.

29. Is it possible for the real rate of return to be less than zero?

Yes. At times the escalation in costs is greater than the return on investment. During those periods, the real rate of return is less than zero, and the nuclear decommissioning trust

(NDT) loses ground to the increasing costs.

30. Has any nuclear decommissioning analysis used a negative real rate of return to calculate the amount of funds needed?

Yes. In 2006 Constellation Energy Group submitted filed a rate case with the Public Service Commission of Maryland for decommissioning costs for the Calvert Cliffs nuclear generating station. The submittal estimated that the after-tax real rate of return for the nuclear decommissioning trust funds was - 0.33% per year.

31. What was the intent of allowing reactor licensees to use PCG as partial satisfaction of the DFA requirement?

In anticipation of the economic deregulation of the electric generation industry, NRC provided a number of lower-cost, flexible methods for reactor licensees to meet the DFA requirements. One of the methods was to allow the combination of a PCG with an external sinking fund, so that merchant plants could gradually build up the sinking fund over time without incurring the financial costs of using LOCs or surety bonds in combination. In the Statement of Considerations to the 1998 Decommissioning Rule, the NRC stated:

> The combination of a parent or self-guarantee and an external sinking fund also appears to provide a relatively low-cost means for licensees to demonstrate financial assurance while continuing to gradually fund decommissioning costs over time (either on the current schedule or on an accelerated schedule). (63 FR 50465, 50473)

32. Why does a merchant plant need full up-front financial assurance?

The NRC explained the need for full up-front assurance from merchant plants with the following statement:

> For licensees that will not be able to collect funds through such a process [through rates] after industry restructuring, up-front assurance is necessary to ensure that reasonable financial assurance is provided for all decommissioning obligations. In the more competitive environment that is likely to prevail after restructuring, some of these licensees may not remain financially viable for reasons not related to decommissioning financial assurance, further suggesting the need for up-front assurance. (63 FR 50465, 50469)

POLICY ISSUE
INFORMATION

June 25, 2010 SECY-10-0084

FOR: The Commissioners

FROM: Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

SUBJECT: EXPLANATION OF CHANGES TO REVISION 2 TO REGULATORY GUIDE 1.159, "ASSURING THE AVAILABILITY OF FUNDS FOR DECOMMISSIONING NUCLEAR REACTORS"

PURPOSE:

On March 25, 2010, the U.S. Nuclear Regulatory Commission (NRC) issued Staff Requirements Memorandum (SRM) M100223B, "Briefing on Decommissioning Funding," directing the staff to provide the Commission with an information paper explaining the changes to the final Regulatory Guide (RG) 1.159, Revision 2, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," and allowing appropriate time to receive Commission direction, if the Commission is so inclined, before issuance of the regulatory guide. This information paper provides the staff response.

SUMMARY:

The NRC issued draft guidance DG-1229, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," in June 2009 to gather public comments on proposed changes to three sections of regulatory guidance that the agency would ultimately issue as RG 1.159, Revision 2. In addition to updating references, the changes would (1) increase the frequency of covering a shortfall in decommissioning financial assurance (the merchant plant licensee frequency would be increased from 2 years to 1 year and the utility licensee frequency would be increased from every 6 years to every rate case) and remove a statement on using

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a reasonable time to make up a deficit, (2) clarify when a real rate of return greater than 2 percent may be credited, and (3) clarify that the earnings credit allowed during a safe storage period following permanent shutdown must reflect any withdrawals needed to maintain the facility in safe storage.

The staff received comments opposing the increased frequency of adjustments. No comments were received on the other 2 proposed changes, which simply document existing staff practice.

The staff concluded that RG 1.159, Revision 2 should include the unopposed changes to clarify the 2 percent return and the earnings credit during safe storage. Regarding the increase in adjustment frequency, the staff evaluated the cost of covering a shortfall within 3 months of the annual escalation adjustment of the minimum amount done on December 31, as required under Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.75(b). The staff found that the commenter's assertions of undue financial burden were contradicted by a number of sources, including financial reports published by parent company owners of reactor licensees. The staff determined that RG 1.159, Revision 2 should include guidance for merchant plant licensees to adjust the actual amount of financial assurance annually, as of March 31 of each year, based on the escalated amount calculated as of the previous December 31. The staff determined that utility licensees would not have to address decommissioning funding in every rate case, but should make a good faith effort to obtain rate relief by requesting their rate regulator to address the issue within the year, and to obtain rate relief as necessary within 5 years.

BACKGROUND:

All power reactor licensees are required to report the status of their decommissioning funds biennially on March 31 of each odd numbered year.[1] Where the amount of financial assurance provided by the licensee is less than the amount required by the regulation, the difference is termed the "shortfall." The NRC now has experience with two equity market downturns, in 2003 and 2009, in which a number of power reactor licensees reported shortfalls.[2] The existing guidance of RG 1.159, Revision 1 states that a merchant plant licensee should make needed adjustments in the level of financial assurance every 2 years, in conjunction with the decommissioning fund status report. For public utility licensees, the existing guidance states that they should obtain rate relief within 6 years.

The NRC issued draft guidance DG-1229 in June 2009 to gather public comments on proposed changes in regulatory guidance. A public meeting held on August 20, 2009, drew over 100 participants to discuss the draft guidance. The Nuclear Energy Institute (NEI) provided extensive written comments, by the end of the comment period in September 2009, which were supported by four industry stakeholders. The comments objected to reducing the time available to cover a shortfall. The comments suggested using case-by-case negotiation without time limits as an acceptable method to resolve shortfalls, and that the NRC should accept net present value (NPV) methods to calculate the size of the shortfall. No comments were received on the proposed clarifications regarding the use of the 2-percent real rate of return or the earnings credit during a period of safe storage. No comments were received supporting the

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1 10 CFR 50.75(f). The report is required annually for licensees involved in mergers or acquisitions; within 5 years of expected shutdown; or permanently shut down.

2 The minimum amount is specified in 10 CFR 50.75(c), which includes a factor for inflation.

proposed changes. Beginning in summer 2009, the staff engaged in case-by-case negotiation with the 26 licensees who had not resolved their shortfalls in their March 2009 decommissioning fund status reports. As of May 2010, four merchant plant facilities (Braidwood 1 and 2, Byron 2, and River Bend) had not resolved their shortfalls. Over 1700 staff hours have been spent on resolving the shortfalls on a case-by-case basis.

The Commission held a public meeting to discuss decommissioning financial assurance on February 23, 2010. Following the meeting, the Commission issued SRM M100223B directing the staff to explain its reasoning for the proposed changes to RG 1.159, Revision 2.

DISCUSSION:

In concluding that existing NRC guidance should be changed to increase the frequency of adjusting financial assurance for decommissioning to annually, the staff considered two major issues.

First, the Commission has often stated that licensees must provide timely and adequate financial assurance for decommissioning costs.[3] The Commission also stated that a licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning.[4] These statements imply that shortfalls, should be avoided where possible and, if they occur, should be covered in a timely manner.

Licensee Performance in Response to Equity Market Declines[5]

Reporting Year	Market Decline from Previous Report	Number of Facilities with Shortfalls	Shortfalls Resolved in 3 Months	Shortfalls Not Resolved in 1 Year
2003	-23%	9	3	0
2009	-30%	27	1	6

Second, the NRC last considered annual adjustments in 2002. Since then, changed circumstances indicate that reconsideration is warranted. The table above summarizes licensee performance in response to the 2003 and 2009 equity market declines. In 2003, about 91 percent of power reactors avoided shortfalls, while in 2009, about 75 percent avoided shortfalls. The number of licensees with shortfalls increased more than expected in relation to the percentage decline in the market. The number of licensees that corrected their shortfalls in 3 months decreased in 2009, although a greater number needed to make corrections.

3 See the following: 53 FR 24030–24031 and 24033, 56 FR 41493, 57 FR 30395, and 67 FR 78332.

4 See 61 FR 39278.

5 Decline calculated from Dow Jones Industrial Average Index closing price on December 31 of the relevant years

Following the 2003 market decline, all licensees resolved their shortfalls within 1 year. In 2009, six licensees did not resolve their shortfalls within 1 year of December 31, 2008. The licensees raised several issues that delayed resolution: 4 licensees claimed the staff should accept NPV methods to calculate the size of the shortfall; 1 licensee provided an incomplete parent company guarantee; and 1 licensee provided a power sales contract which is under review by the staff. Comparing 2009 to 2003, the number of facilities with shortfalls increased by 18, of which 16 were merchant plants.[6] The staff concluded that (1) the data indicated an apparent trend toward less adequate and less timely financial assurance in response to an equity market decline, and (2) case-by-case negotiation with each licensee to resolve a shortfall appeared to be less effective in 2009.

The timing and severity of market fluctuations are outside licensee control. However, licensees have the ability to make forward-looking plans to account for the inescapable volatility of the markets. Licensees can control a variety of measures to manage financial risks.[7] Three-fourths of power reactors avoided shortfalls in 2009, thus demonstrating that successful forward-looking plans are available.

Licensees can also control their response to a shortfall, if it occurs. For example, following the 2002 equity market decline, Progress Energy provided PCGs totaling $276 million to supplement financial assurance at three of its public utility reactor facilities within 3 months of the end of the decommissioning fund status reporting period. Its action demonstrate that a licensee can cover a substantial shortfall within 3 months without suffering the adverse effects asserted by comments submitted in opposition to the proposed annual frequency for covering shortfalls.

The staff considered periods of 1 to 3 years for the frequency of adjustments to cover shortfalls. The staff determined, based on experience with the Connecticut Yankee (CY) facility, that allowing 3 years to resolve a shortfall could increase the risk that a licensee would lack adequate funds to complete decommissioning. CY was a regulated electric utility. In CY's case, the licensee conducted periodic market studies to determine the economic viability of the plant. Unfortunately, CY's outlook reversed from viable to nonviable within 3 years as the result of price competition. A decrease in competitive prices of about 7 percent resulted in a decision to immediately shut down the plant and begin decommissioning. When the shutdown occurred, CY's rate collections had not yet accumulated adequate funds for decommissioning.[8] CY was able to pay for decommissioning because of its status as an electric utility with access to several hundred million dollars in additional ratepayer funds, after going through contentious rate proceedings.

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6 In 2003, the total included 8 utility facilities and 1 merchant facility, In 2009, the total included 9 public utility facilities, 16 merchant plant facilities, and 2 facilities that were "hybrids," with both utility and merchant licensee owners.

7 For instance, licensees control how much exposure to market risk they will accept when they give instructions to their fund managers. They can increase or decrease their reliance on future earnings to pay for decommissioning. They can arrange to obtain guarantees to cover shortfalls before the fact, at favorable rates, or choose to wait until after the fact and face potentially higher rates. They can choose to maintain a higher fund balance to withstand volatility or a lower balance that is vulnerable to volatility.

8 The regulations do not require licensees to possess the full amount of cash needed for decommissioning until the time of permanent shutdown. However, licensees must provide financial assurance that they can obtain the funds at any time during the life of the facility. *See* footnotes 3 and 4, *supra*.

However, the CY experience emphasizes the need for full up-front financial assurance from a merchant plant licensee that has no access to ratepayer funds to cover shortfalls, but faces at least equal competitive pressures.

The staff considered the 2-year frequency to be a suboptimal adjustment frequency. First, the 2-year frequency appears to be getting less effective in encouraging licensees to make forward-looking plans to avoid shortfalls. Second, if a merchant plant delays covering the shortfall for over a year, as happened in several cases in 2009, the 2-year period can extend beyond 3 years.

The staff found that the cost of covering a shortfall on an annual basis is minimal using a PCG and is a very small percentage of net income using other guaranty methods. Annual adjustment of the actual amount of financial assurance provided would encourage licensees to use forward-looking plans to avoid shortfalls, and would align with the Commission's policy that licensees are required to provide adequate financial assurance at any time during the life of the facility. The adjustment of the actual amount provided would coincide with the existing requirement to make an annual escalation adjustment to the minimum requirement, as required by the provisions of 10 CFR 50.75(b)(2) and (c)(2).

The staff considered the comments received on the draft guidance of DG-1229. As noted in the Progress Energy example, the commenter's assertions of undue financial burden are contradicted by actual licensee experience. The staff found that NEI did not adequately consider the effects of equity market volatility on the ability of a licensee to provide funds when needed for decommissioning when relying on market gains to cover future expenses. The enclosure provides details of the staff's consideration of the comments.

The staff declined the suggestion to provide guidance recommending case-by-case negotiation without time limits as a method to resolve shortfalls on the grounds that the Commission rejected the case-by-case approach to decommissioning financial assurance when it issued its 1988 Decommissioning Rule.[9]

The staff declined the suggestion to provide guidance recommending the net present value method for calculating the size of a shortfall on grounds that it underestimated the amount.

In view of the information summarized above, the staff concluded that the NRC's guidance should recommend an increased frequency for adjusting the level of financial assurance to cover a shortfall.

For merchant plant licensees, the guidance will state that the level of financial assurance should be adjusted to cover shortfalls annually, by March 31 of each year.

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[9] See Volume 53, page 24019, of the Federal Register (53 FR 24019). However, in the case of prematurely shutdown reactors, the Commission concluded that a case-by-case approach was necessary. See 57 FR 30383, 30394. The Commission may also take actions as appropriate on a case-by-case basis to modify a licensee's schedule for the accumulation of decommissioning funds. See 10 CFR 50.75(e)(2).

For utility licensees, the NRC has a policy to minimize its involvement with the rate regulatory process.[10] However, a commenter requested that the staff include guidance on good-faith efforts to seek rate relief. Accordingly, the staff will include guidance for a utility licensee to inform its rate regulator by March 31 of each year when a shortfall occurs as of the preceding December 31 and request its rate regulator to review decommissioning cost recovery within the year.

The staff will continue its practice of monitoring the adequacy of financial assurance for decommissioning in conjunction with the decommissioning fund status report submitted by licensees. However, the staff may increase the frequency of its reviews, if necessary, under the provisions of 10 CFR 50.75(e)(2), which allow the NRC to review and take appropriate action with respect to decommissioning financial assurance, either independently or in cooperation with a licensee's rate regulator.

COORDINATION:

There are no resource implications in this paper. The Office of the General Counsel has reviewed this paper and has no legal objection.

/RA/

Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Enclosures:
1. Summary of NRC Financial Assurance Requirements
2. Response to Comments on DG-1229
3. Staff Calculation Using 2 Percent Earnings
4. Licensee Calculation Using Net Present Value Methods
5. Proposed Changes to Final RG 1.159, Revision 2

[10] See 53 FR 24030.

Summary of NRC Decommissioning Financial Assurance Requirements for Power Reactors

- Basic Objectives:
    1. Protect the public from the significant radiation hazard of non-decommissioned nuclear reactors (53 FR 24033)
    2. Assure that lack of funds does not delay safe and timely decommissioning (53 FR 24033)
        a. Full funding of decommissioning at the time of permanent shutdown (53 FR 24030-31, 56 FR 41493, 57 FR 30395, 67 FR 78332)
        b. A licensee is required to provide adequate financial assurance at any time during the life of the facility, through termination of the license (61 FR 39278)
    3. Provide flexibility in financial assurance methods (63 FR 50468)
    4. Minimize administrative effort required of the NRC and licensees to establish financial assurance (53FR 24030)
    5. Minimize NRC involvement with rate regulatory process (53 FR 24030)
    6. For merchant plants, full up-front financial assurance (63 FR 50469)
    7. Reserve the right to review and modify fund accumulation schedule (10 CFR 50.75(e)(2)

- The three step regulatory process before permanent shutdown (53 FR 24030-31) includes:
    1. Initial certification that minimum requirement has been provided
    2. Periodic adjustment for inflation
        a. Annual adjustment of minimum requirement in accordance with specified escalation rate (10 CFR 50.75(b)(2) and (c)(2))
    3. Site-specific cost estimate 5 years prior to permanent shutdown

- Minimum requirement for decommissioning financial assurance (10 CFR 50.75(c)(1) and (2)):
    1. Formula in 1986 dollars:
        a. PWR millions = $(75 + 0.0088*MWt), max. $105
        b. BWR millions = $(104 + 0.009*MWt), max. $135
    2. Escalation = 0.65 L + 0.13 E + 0.22 B, factors published in NUREG-1307

- Criteria for evaluating funding methods (50 FR 5607-08):
    1. Most important: degree of assurance
    2. Important: cost of providing assurance

- Periodic monitoring using decommissioning fund status report (10 CFR 50.75(f))

- Methods available for providing financial assurance for decommissioning (10 CFR 50.75(e)):
    1. Funds held in trust, including projected earnings at up to 2% annually, or higher rate if authorized by the licensee's rate regulator
    2. Guaranty methods:
        a. Letter of credit
        b. Surety or insurance
        c. Parent company guarantee & self-guarantee
    3. Contractual obligations, if adequate guarantee of payment is included
    4. Statements of intent, if a government licensee
    5. Combinations of above and other methods proposed by licensee, if they provide equivalent degree of assurance

Response to Comments on Draft Guidance DG-1229,

“Assuring the Availability of Funds for Decommissioning Nuclear Reactors”

Response to Comments on Draft Guidance DG-1229, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors"

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Executive Summary

In concluding that guidance on the frequency of adjusting financial assurance for decommissioning should be increased to annually, the staff of the U.S. Nuclear Regulatory Commission (NRC) considered two major issues.

First, the Commission has often stated that licensees must provide timely and adequate financial assurance for decommissioning costs.[1] The Commission has also stated that a licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning.[2] These statements imply that shortfalls, which are occasions when the licensee's financial assurance does not meet the regulatory minimum requirement, should be avoided where possible and, if they occur, should be covered in a timely manner.

Second, the NRC last considered annual adjustments in 2002. Since then, as noted below, the timeliness and adequacy of license response to covering shortfalls has apparently decreased. These changed circumstances indicate that reconsideration is warranted.

The staff compared licensee performance in covering shortfalls in decommissioning financial assurance in response to the 2003 and 2009 equity market declines. Where the licensee provides financial assurance in an amount less than the amount required by regulation, the difference is termed the "shortfall." In 2003, about 91 percent of power reactors avoided shortfalls, while in 2009, about 75 percent avoided shortfalls. The number of licensees with shortfalls increased more than expected in relation to the percentage decline in the market. The number of licensees that took self-initiated action to correct their shortfalls decreased in 2009, although a greater number needed to make corrections. Following the 2003 market decline, all licensees resolved their shortfalls within 1 year. In 2009, six licensees took over a year to resolve their shortfalls. The licensees raised several issues that delayed resolution: 4 licensees claimed the staff should accept net present value methods to calculate the size of the shortfall; 1 licensee provided an incomplete parent company guarantee; and 1 licensee provided a power sales contract which is under review by the staff. The staff concluded that (1) the data indicated an apparent trend toward less adequate and less timely financial assurance in response to an equity market decline and (2) case-by-case negotiation with each licensee to resolve a shortfall appeared to be less effective in 2009.

The NRC issued draft guidance DG-1229, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," in June 2009 to gather public comments on proposed changes to three sections of regulatory guidance that the agency would ultimately issue as RG 1.159, Revision 2. In addition to updating references, the changes would (1) increase the frequency of covering a shortfall in decommissioning financial assurance (the merchant plant licensee frequency would be increased from 2 years to 1 year and the utility licensee frequency would be increased from every 6 years to every rate case) and remove a statement on using a reasonable time to make up a deficit, (2) clarify when a real rate of return greater than 2 percent may be credited, and (3) clarify that the earnings credit allowed during a safe storage period

1 See the following *Federal Register* (FR) notices: 53 FR 24030–24031 and 24033, 56 FR 41493, 57 FR 30395, and 67 FR 78332.

2 See 61 FR 39278.

following permanent shutdown must reflect any withdrawals needed to maintain the facility in safe storage.

No comments were received on the proposed changes to clarify the use of the 2-percent real rate of return or the earnings credit during a period of safe storage. The Nuclear Energy Institute (NEI) opposed the increased frequency of adjusting the amount of financial assurance to cover a shortfall for a variety of reasons, primarily based on cost. Additional objections were raised that (a) the guidance had no safety benefit, (b) a notice-and-comment process should have been used to change the guidance, (c) the successful history of funding reactor decommissioning rendered changes unnecessary, and (d) the long investment horizon to accumulate funds provided additional assurance that funds would be available, based on the low probability that any currently operating reactor will be decommissioning in the next several decades. The comments objected to the methods used by NRC to calculate the amount of a shortfall in financial assurance provided by a licensee. The comments suggested that (a) licensees should be permitted to resolve shortfalls using case-by-case negotiations without time limits, (b) rate-regulated licensees should not be requested to address decommissioning funding in every rate case, and (c) that guidance should be provided on making a good faith effort to address shortfalls in ratemaking proceedings. A comment suggested updating references in the guidance. Four industry stakeholders submitted comments expressing support of NEI's comments. No comments were received supporting the proposed changes.

The Nuclear Energy Institute (NEI) noted that the NRC's long-standing position has been to handle the frequency of adjustments to decommissioning funding in guidance. NEI nevertheless objected to the proposed guidance on grounds that the draft guidance interpreted the NRC's regulations in a new way. The staff concluded that NEI's objection was not persuasive on grounds that the proposed guidance to cover shortfalls annually is within the scope of the Commission's long-standing policy that the licensee is required to provide assurance at any time during the life of the facility.

The staff concluded that the commenters overestimated the costs of covering a shortfall. The staff evaluation found that covering a shortfall with a parent company guarantee had essentially no cost and using a letter of credit or a surety was a very small percentage of the net income earned by the licensees. In view of the flexibility of the NRC's financial assurance methods, the staff concluded that the cost of covering a shortfall was not an undue financial burden.

The commenters argued that the expected long time horizon before decommissioning is likely to be necessary would justify a delay in covering a shortfall. The staff disagreed for several reasons. For example, the staff reviewed annual reports to shareholders and to the Securities and Exchange Commission prepared by parent companies that own power reactor licensees. Those reports identified significant costs to the companies in the event that the decommissioning trust funds underperformed over a period of time. The staff concluded that excessive reliance on market growth could delay decommissioning due to lack of funds. The staff also concluded that an expectation of market growth in excess of the 2-percent real rate of return provided in NRC regulations did not justify a delay in covering a shortfall. In addition, as noted above, the Commission's policy requires licensees to provide adequate financial assurance at any time during the life of the facility, and the cost, if any, to cover a shortfall falls within the range contemplated in the decommissioning rule.

The staff found that a 3-year frequency for adjusting financial assurance for decommissioning could increase the risk that funds would not be available when needed for decommissioning, based on experience with the Connecticut Yankee plant. In that case, the licensee's business outlook reversed from viable to nonviable in a 3-year period, which led to a decision to immediately and permanently shut down the plant. The 2-year frequency was apparently becoming less effective, as evidenced by the trend observed between 2003 and 2009 in the decommissioning fund status reports. The staff concluded that adjusting the level of assurance on an annual basis was optimal due to low cost and the reduction in the likelihood that decommissioning would be delayed because of a lack of funds. The annual frequency would apply to all licensees. The adjustment of the actual amount provided would coincide with the existing requirement to make an annual escalation adjustment to the minimum requirement, as required by the provisions of 10 CFR 50.75(b)(2) and (c)(2).

The commenter suggested that licensees be permitted to use case-by-case negotiation without time limits to resolve a shortfall. In 2009, over 1,700 staff hours were spent in case-by-case negotiation to resolve shortfalls reported by 27 licensees. The staff declined the commenter's suggestion on the grounds that the Commission had rejected the case-by-case approach to decommissioning in its 1988 Decommissioning Rule in order to minimize the administrative burden on the agency and the licensees.[3]

The commenter suggested that licensees should be permitted to use net present value (NPV) methods to calculate the size of a shortfall. The staff declined this suggestion on the grounds that NPV methods can underestimate the size of a shortfall.

The commenter suggested that guidance should be provided on using good-faith efforts by electric utility licensees to obtain rate relief. The staff agreed. The staff will include guidance for a utility licensee to inform its rate regulator by March 31 of each year when a shortfall occurs as of the preceding December 31 and request that its rate regulator review decommissioning cost recovery within the year.

[3] 53 FR 24019

Introduction

In coming to the conclusion that guidance on the frequency of adjusting financial assurance for decommissioning should be revised from 2 years to 1 year for merchant plant licensees, the staff of the U.S. Nuclear Regulatory Commission (NRC) considered two major issues.
First, the Commission often stated that licensees must provide timely and adequate financial assurance for decommissioning costs.[1] The Commission has also stated that adequate funds to complete decommissioning must be available at any time during the life of the facility, through termination of the license.[2] These statements imply that shortfalls, which are occasions when the licensee's financial assurance does not meet the regulatory minimum requirement, should be avoided where possible and, if they occur, covered in a timely manner.

Second, the NRC last considered annual adjustments in 2002. Since then, changed circumstances indicate that reconsideration is warranted. Table 2, presented in the discussion of Comment 5, "Case-by-Case Negotiation," summarizes licensee performance in response to the 2003 and 2009 equity market declines. In 2003, about 91 percent of power reactors avoided shortfalls, while in 2009, about 75 percent avoided shortfalls. The number of licensees with shortfalls increased more than expected in relation to the percentage decline in the market. The number of licensees that took self-initiated action to correct their shortfalls decreased in 2009, although a greater number needed to make corrections. Following the 2003 market decline, all licensees resolved their shortfalls within 1 year. In 2009, six licensees took over a year to resolve their shortfalls. The licensees raised several issues that delayed resolution: 4 licensees claimed the staff should accept NPV methods to calculate the size of the shortfall; 1 licensee provided an incomplete parent company guarantee; and 1 licensee provided a power sales contract which is under review by the staff. The staff concluded that (1) the data indicated an apparent trend to less adequate and less timely financial assurance in response to an equity market decline and (2) case-by-case negotiation with each licensee to resolve a shortfall appeared to be less effective in 2009.

The timing and severity of market fluctuations are outside licensee control. However, licensees have the ability to make forward-looking plans to account for the inescapable volatility of the markets. Licensees can control a variety of measures to manage financial risks. Three-fourths of power reactors avoided shortfalls in 2009, which demonstrates that successful forward-looking plans are available.

Licensees can also control their response to a shortfall, if it occurs. The staff reviewed a case in which a parent company with three power reactor facilities had shortfalls in the 2002 equity market decline. The parent company provided guarantees to supplement the licensee's financial assurance within 3 months of the end of the fund status reporting period on December 31.

The staff considered periods of 1 to 3 years for the frequency of adjustments to cover shortfalls. The staff determined, based on experience with Connecticut Yankee (CY), that allowing 3 years to resolve a shortfall could increase the risk that a merchant plant licensee would lack adequate funds to complete decommissioning. In CY's case, the licensee conducted periodic market studies to determine the economic viability of the plant. Unfortunately, CY's outlook reversed

[1] See the following *Federal Register* (FR) notices: 53 FR 24030–31 and 53 FR 24033, 56 FR 41493, 57 FR 30395, and 67 FR 78332.

[2] 61 FR 39278.

from viable to nonviable within 3 years due to price competition. A decrease in competitive prices of about 7 percent resulted in a decision to immediately shut down the plant and begin decommissioning. CY was able to pay for decommissioning due to its status as an electric utility with access to several hundred million dollars in additional ratepayer funds. A merchant plant faces at least equal competitive pressures, but has no access to ratepayer funds to cover shortfalls in its decommissioning funding.

The staff considered a 2-year frequency to be a suboptimal adjustment frequency. First, the 2-year frequency appears to be less effective in encouraging licensees to make forward-looking plans to avoid shortfalls. Secondly, if a merchant plant delays covering the shortfall for over a year, as happened in several cases in 2009, the 2-year period can extend beyond 3 years, thus increasing the risk that the licensee would lack funds to complete decommissioning.

On the other hand, the cost of covering a shortfall on an annual basis is minimal using a parent company guarantee (PCG) and reasonable using other guaranty methods. The staff concluded that covering a shortfall in 1 year would strengthen the licensee's ability to avoid a shortfall the next year. Covering shortfalls annually would not significantly increase costs, but would encourage licensees to use forward-looking plans to avoid shortfalls and would reduce the risk that a licensee would lack funds to complete decommissioning. The adjustment of the actual amount provided would coincide with the existing requirement to make an annual escalation adjustment to the minimum requirement, as required by the provisions of 10 CFR 50.75(b)(2) and (c)(2).

The staff considered the comments received on the draft guidance of DG-1229. The staff concluded that the commenter overestimated the cost of covering a shortfall, in part due to misreading the regulatory requirements for a PCG as stated in Appendix A, "Criteria Relating to Use of Financial Tests and Parent Company Guarantees for Providing Reasonable Assurance of Funds for Decommissioning," to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 30, "Rules of General Applicability to Domestic Licensing of Byproduct Material." The cost to cover a shortfall ranged from minimal to reasonable. The staff found that the commenter did not adequately consider the effects of equity market volatility and unpredictability on the ability of a licensee to provide funds when needed for decommissioning. However, a number of sources provided information on the potential adverse effects of market uncertainty that contradicted the commenter.

In view of the information currently available, the staff concluded that 1 year is the optimal frequency for merchant plants to adjust financial assurance to meet the regulatory requirement.

For utility licensees, the NRC has a policy to minimize its involvement with the rate regulatory process.[3] However, a commenter requested that the staff include guidance on good-faith efforts to seek rate relief. Accordingly, the staff will include guidance for a utility licensee to inform its rate regulator by March 31 of each year when a shortfall occurs as of the preceding December 31 and request its rate regulator to review decommissioning cost recovery within the year, and obtain rate relief as necessary within 5 years.

[3] See 53 FR 24030.

Changes Proposed to Regulatory Guidance

The NRC issued draft guidance DG-1229, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," in June 2009 to gather public comments on a proposed change in regulatory guidance. Substantive changes were made in three sections: 1.3, "Decommissioning Cost Estimates"; Section 2.1.5 within Section 2.1, "Guidance Applicable to All Methods of Financial Assurance"; and Section 2.2.8 within Section 2.2, "Prepayment and External Sinking Fund."

The changes within Section 1.3 added references to related regulatory guidance issued after Revision 1 to Regulatory Guide 1.159 was issued in 2003. The changes within Section 2.1.5 relate to a change in the frequency for making adjustments to the licensee's financial assurance amounts and mechanisms. For merchant plants, the proposed frequency was increased from at least once every 2 years, in conjunction with the biennial report, to annually, at the end of each calendar year. For utility licensees, the proposed frequency was increased from once every 6 years to every rate case. Finally, changes were proposed to Section 2.2.8 to remove a statement on using a reasonable time to make up a deficit; clarify when greater than a 2-percent real rate of return may be credited; and state that the credit allowed during a safe storage period following permanent shutdown must reflect any withdrawals needed to maintain the facility in safe storage.

Description of Comments Received on Proposed Changes

The Nuclear Energy Institute (NEI) opposed the increased frequency of adjusting the amount of financial assurance to cover a shortfall for a variety of reasons, primarily based on cost. Additional objections were raised that (a) the guidance had no safety benefit, (b) a notice-and-comment process should have been used to change the guidance, (c) the successful history of funding reactor decommissioning rendered changes unnecessary, and (d) the long investment horizon to accumulate funds provided additional assurance that funds would be available, based on the low probability that any currently operating reactor will be decommissioning in the next several decades. The comments objected to the methods used by NRC to calculate a shortfall in the amount of financial assurance provided by a licensee. The comments suggested that (a) licensees should be permitted to resolve shortfalls using case-by-case negotiations without time limits, (b) rate-regulated licensees should not be requested to address decommissioning funding in every rate case, and (c) that guidance should be provided on making a good faith effort to address shortfalls in ratemaking proceedings. A comment suggested updating references in the guidance.

Two power reactor licensees submitted comments. The Tennessee Valley Authority (TVA) generally supported the NEI comments. Detroit Edison supported NEI's comment that the guidance should not state that public utility licensees should address decommissioning funding at every rate case.

One power reactor organization, Strategic Teaming and Resource Sharing (STARS), supported several of the NEI comments. STARS made an additional comment that 3 months is too little time to address a shortfall.

One prospective transferee for a decommissioning power reactor license, EnergySolutions, supported several of NEI's comments. EnergySolutions added that, for some licensees, the

cost of a letter of credit (LOC) may be higher than NEI's estimates. EnergySolutions also added that, under strongly negative market conditions, such as occurred in 2008, the cost of an LOC can increase, and, perhaps, be unavailable at any price.

Changes Made in the Final Version of Regulatory Guidance

The annual frequency for adjusting the level of financial assurance was retained in Section 2.1.5 of RG 1.159. However, guidance on making a good-faith effort to obtain rate relief was added to Section 2.1.5. The guidance will instruct the licensee to inform its rate regulator when a shortfall occurs and to request that the rate regulator review decommissioning financial assurance within a year.

Definitions for "shortfall," and "decommissioning financial assurance" were added to the glossary of RG 1.159. "Shortfall" is discussed in the section titled, "NRC's Evaluation Method for Decommissioning Financial Assurance," of this paper. "Financial assurance" is discussed in Comment 15, "Cash Contributions Cause Overfunding," of this paper.

The revisions proposed for Section 1.3 and Section 2.2.8 were retained without change.

NRC's Evaluation Method for Decommissioning Financial Assurance

An important tool used by the staff to evaluate licensee financial assurance is the cash flow analysis. The cash flow analysis projects the amount of funds available to the licensee from all assured sources of funding and subtracts the projected decommissioning expenses. If all expenses are covered, the assurance is adequate. If the assured funds run out before all decommissioning expenses are paid, a shortfall occurs. The amount of the unfunded expenses equals the shortfall. When a shortfall occurs, the licensee does not meet the regulatory requirement to provide adequate financial assurance for decommissioning.

A simplified example showing a shortfall appears in Table 1 below.[4] The NRC specifies the minimum acceptable amount of financial assurance for decommissioning in 10 CFR 50.75(c), which includes an inflation adjustment. For the example, the minimum requirement was set at $500 million. The example shows an analysis starting 10 years before expected shutdown for a licensee that plans to begin decommissioning immediately after shutdown. At the beginning of Year 1, the licensee has accumulated $350 million in its decommissioning trust fund. To determine whether the accumulated funds provide adequate financial assurance, the staff projects the expenses and the earnings. Seven years is the default period to complete decommissioning, as stated in the regulations.[5] For the default case, the cash flow analysis assumes 1/7 of the total requirement is spent each year, so the total decommissioning expenses equal the minimum requirement. NRC regulations allow the licensee to include

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4 Detailed instructions for doing the evaluation are in LIC-205, "Procedures for NRC's Independent Analysis of Decommissioning Funding Assurance for Operating Nuclear Power Reactors," issued March 2010. (Agencywide Documents Access and Management System (ADAMS) Accession No. ML100550465)

5 10 CFR 50.75(e)(i) and 10 CFR 50.75(e)(ii) set the 7 year default period. However, a licensee may plan to take up to 60 years to complete decommissioning by providing a site-specific cost estimate that may not be less than the required minimum of 10 CFR 50.75(c). The licensee must account for any additional costs not included in the basis for the minimum amount. The licensee can specify any expense pattern that suits its needs. If the staff agrees that the proposed expense pattern is reasonable, it will perform the cash flow analysis in a manner similar to the example.

earnings on its accumulated funds up to 2-percent real rate of return.[6] The example shows the 2-percent annual real rate of return calculated each year on the accumulated funds. For the example, only the accumulated funds and the earnings credit are shown. However, in an actual case, the amount of financial assurance may include guaranteed amounts, future ratepayer collections, and future payments under contractual obligations.[7]

Table 1. Example Cash Flow Analysis ($ Thousands)

Minimum required financial assurance = $500,000
Ending balance = Beginning Balance - Expense + 2% Earnings

Year	Beginning Fund Balance	Decommissioning Expense	2% Earnings	Ending Fund Balance
		Operation		
1	350,000	0	7,000	357,000
2	357,000	0	7,140	364,140
3	364,140	0	7,283	371,423
4	371,423	0	7,428	378,851
5	378,851	0	7,577	386,428
6	386,428	0	7,729	394,157
7	394,157	0	7,883	402,040
8	402,040	0	8,041	410,081
9	410,081	0	8,202	418,282
10	418,282	0	8,366	426,648
		Decommissioning		
11	426,648	71,429	8,533	363,752
12	363,752	71,429	7,275	299,599
13	299,599	71,429	5,992	234,162
14	234,162	71,429	4,683	167,417
15	167,417	71,429	3,348	99,337
16	99,337	71,429	1,987	29,895
17	29,895	71,429	0	**(41,534)**
	Total	500,000	109,064	

This example shows that the licensee will run out of money before completing decommissioning. No earnings are shown in the year the money runs out since the NRC's calculation method subtracts the annual expense before calculating the earnings credit. The negative fund balance in Year 17 represents the difference between the amount of financial assurance provided and the amount required by regulation. The amount of the unassured expense is the shortfall. In the example, the assurance is not adequate, and the licensee is required to produce additional financial assurance in Year 1 in the amount of $41.5 million to cover the shortfall. The coverage may be a cash deposit into the decommissioning trust or any

6 A public utility licensee may use a real rate-of-return credit greater than 2 percent if authorized by its rate regulator

7 The full list of available methods is specified in 10 CFR 50.75(e)(1).

other approved method, such as a parent company guarantee or other non-cash method. If a cash deposit is made in Year 1 of the example, the 2-percent earnings credit can be included. If a non-cash method is used, then no earnings may be credited since there are no funds to produce the earnings.

Response to Comments

The NRC received comments criticizing the proposed guidance that merchant plant licensees should adjust the amount of financial assurance annually to meet the minimum required amount of financial assurance specified in 10 CFR 50.75, "Reporting and Recordkeeping for Decommissioning Planning." Some comments suggested changes to the proposed guidance. The staff responses to the comments are organized into several categories as listed below.

SAFETY

Comment 1 No Health and Safety Benefit

The proposed guidance is without any benefit to the health and safety of the public.

Response 1

The staff disagreed. The shortfalls reported in 2009 ranged from about $500,000 to $199 million per reactor.[8] The commenter did not explain why shortfalls in meeting the NRC's minimum required amount of financial assurance presented no risk of delay to the safe and timely decommissioning of the reactors involved. Instead, the commenter asserted that an annual adjustment of financial assurance to meet the required minimum amount was unnecessarily restrictive and an undue financial burden. The comments asserted that the current economic outlook for the nuclear generation business made it unlikely that any plant would decommission in the near future. However, assertions of burden and expectations of profitable business conditions do not provide a basis for finding that no safety risk exists when the licensee does not provide adequate financial assurance for decommissioning.

On the other hand, the NRC has an extensive body of knowledge to demonstrate that a nondecommissioned reactor presents a significant radiation hazard. The NRC based its conclusion on a series of NUREG/CR reports produced by Battelle Pacific Northwest Laboratories, staff position papers presented in NUREG reports, a generic environmental impact statement noticed in the *Federal Register*, and responses to comments received from stakeholders.[9] When it issued the 1988 Decommissioning Rule, the NRC explained that inadequate or untimely financial assurance for decommissioning poses a significant risk to the health and safety benefit of the public, as expressed below:

> Inadequate or untimely consideration of decommissioning, specifically in the areas of planning and financial assurance, could result in significant adverse health, safety and environmental impacts. These impacts could lead to

[8] SECY-09-0146, "2009 Summary of Decommissioning Funding Status Reports for Nuclear Power Reactors," p. 5, October 6, 2009.

[9] 53 FR 24018, 21019, General Requirements for Decommissioning Nuclear Facilities, Final Rule, July 27, 1988 (hereinafter referred to as the 1988 Decommissioning Rule).

> increased occupational and public doses, increased amounts of radioactive waste to be disposed of, and an increase in the number of contaminated sites. These regulations make clear that the licensee is responsible for the funding and completion of decommissioning in a manner which protects public health and safety.…[10]
>
> The NRC has also determined that the public health and safety can best be protected if its regulations require licensees to use methods which provide reasonable assurance that, at the time of termination of operations, adequate funds are available so that decommissioning can be carried out in a safe and timely manner and that lack of funds does not result in delays that may cause potential health and safety problems.[11]

A shortfall occurs when the amount of financial assurance provided by the licensee falls short of the regulatory requirement of 10 CFR 50.75(c). A licensee with a shortfall cannot ensure that it will have enough money to safely complete decommissioning in a timely manner. That potential delay presents a risk to workers, the public, and the environment.

COMMENTS ON PROCESS

Comment 2 Notice-and-Comment Required

The proposed guidance in DG-1229 is a substantial change in the interpretation of 10 CFR 50.75. Therefore, the NRC cannot change its existing guidance to recognize annual adjustments as an acceptable method to implement the requirements of 10 CFR 50.75 without using a notice-and-comment process.

Response 2

The staff disagreed. The Commission published its interpretation of the requirements of 10 CFR 50.75 in 1996, as stated below:

> A licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning.[12]

The annual adjustment frequency of the proposed guidance falls within the scope of providing assurance "at any time." To clarify the point, the final version of the guidance will include the Commission interpretation quoted above.

In addition, the NRC followed a notice-and-comment procedure for issuing the proposed guidance. The following recitation describes the notice-and-comment efforts taken to support the issuance of the guidance. The Commission issued a Notice of Issuance and Availability of Draft Regulatory Guide in the *Federal Register* on June 30, 2009.[13] The Notice solicited

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[10] 1988 Decommissioning Rule at 53 FR 24019.
[11] 1988 Decommissioning Rule at 53 FR 24033.
[12] Decommissioning of Nuclear Power Reactors, Final Rule, 61 FR 39278, July 29, 1996.
[13] Notice of Issuance and Availability of Draft Regulatory Guide, 74 FR 31317, June 30, 2009.

comments on the draft guidance and provided instructions on submitting comments to the NRC. A comment period was established from June 30 through September 9, 2009. The NRC issued a Notice of Forthcoming Public Meeting on July 16, 2009, to inform stakeholders that a public meeting would be held in Bethesda, MD, to gather comments on the draft guidance.[14] The meeting was held as scheduled on August 20, 2009, and attracted over 100 participants via personal attendance, telephone, and Webinar. Representatives of NEI attended the public meeting. The comment period ended in September 2009, and five written comments were received. NEI provided three versions of its comments to the NRC.[15] The staff considered the comments in its final revision of the guidance.

Comment 3 Use of Guidance to Handle the Frequency of Adjustments

The NRC's long-standing position has been to handle the frequency of adjustments to decommissioning funding levels through guidance.

Response 3

The staff agreed. The NRC will continue that position by issuing guidance to handle the change to the frequency of adjustment to the amount of decommissioning financial assurance provided by a licensee.

Comment 4 NRC Rejected Annual Adjustment as Guidance in 2002

In 2002, as noted in the *Federal Register*, in response to a stakeholder comment, the NRC considered and rejected issuing guidance recommending annual funding adjustments for merchant plant licensees.

Response 4

The staff agreed that an annual funding adjustment for merchant plants was considered and rejected as guidance in 2002. However, due to changed circumstances, the annual adjustment frequency merits reconsideration.

In 2002, no licensee had reported a shortfall in its financial assurance coverage. Since then, the NRC has gained experience with two significant equity market declines that resulted in shortfalls in 2003 and 2009.[16] The historical data on the number of licensees with shortfalls, as summarized in Table 2 and discussed in Comment 5, "Case-by-Case Negotiation," indicate a potential trend to less adequate and less timely financial assurance. For example, in 2009, 26 of 27 licensees with shortfalls did not provide a plan to cover the shortfall until directed to do so

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14 Notice of Forthcoming Category 3 Public Meeting With Stakeholders to Discuss Issues Related to Biennial Decommissioning Funding Report Analysis Process (ML091970301)

15 ML092590127, ML092590128, and ML092930272

16 A third series of shortfalls occurred in 2005, but were unrelated to equity market declines. Six licensees owned by Exelon had erroneously used earnings credits in excess of the regulatory allowance when they calculated the amount of financial assurance they provided. The shortfalls were resolved by using a SAFSTOR cash flow analysis that extended the earnings period, but limited earnings to 2 percent per annum. (ADAMS Accession No. ML071070368)

by the NRC.[17] The data on licensee responses to the shortfalls in 2003 and 2009 suggest that the 2-year adjustment period is less effective than when it was first issued. As discussed in Comment 5, "Case-by-Case Negotiation," in 2003, 91 percent of licensees did not have shortfalls, and three licensees followed the existing guidance to adjust the amount of financial assurance in conjunction with the biennial decommissioning fund status report. In 2009, 75 percent of licensees had shortfalls, and 1 licensee resolved its shortfall in conjunction with its biennial decommissioning fund status report.

The circumstances outlined above conflict with the Commission's policy that "A licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning."[18]

A shortfall, by definition, indicates that the financial assurance provided by the licensee is not adequate. The 2-year adjustment frequency for merchant plant licensees placed in guidance in 2002 appeared sufficient at the time to implement the Commission policy stated above. In view of the apparent trend to less adequate and less timely financial assurance, the staff concluded that changed circumstances indicate that annual adjustment of financial assurance is appropriate.

As a final point, the staff noted that the basis of the stakeholder comment submitted in 2002 was that annual adjustments to investments held in the decommissioning trust could be expensive. However, the NRC provides other financial assurance methods that do not require adjustments to invested funds. For example, the cost of the guarantee methods ranges from minimal to a very small percentage of net income. Consequently, issuing guidance to cover shortfalls on an annual basis will not require adjustment of invested funds, which resolves the objection presented in the 2002 comment.

Comment 5 Case-by-Case Negotiation

Licensees should be permitted to resolve shortfalls after they occur using case-by-case negotiation with no time guideline for completion.

Response 5

The staff declined NEI's suggestion to resolve shortfalls after they occur using case-by-case negotiations with no time guideline for completion for the following reasons.

First, by definition, when a shortfall occurs the licensee does not provide an adequate amount of financial assurance. The Commission stated that inadequate and untimely consideration of financial assurance increases the potential risk to the public and the environment of significant adverse health and safety impacts that could occur if decommissioning is delayed due to lack of funds.[19] In view of the increased financial risk caused by a shortfall, it follows that minimizing the time period that a shortfall persists reduces the risks to public health and safety associated with a nondecommissioned reactor. Case-by-case negotiation increases the time a shortfall

17 During the summer of 2009, the NRC issued letters to 26 licensees directing them to provide a plan of action to cover the shortfalls. One licensee submitted a plan on its own initiative to resolve its shortfall.

18 Decommissioning of Nuclear Power Reactors, Final Rule, 61 FR 39278, July 29, 1996.

19 1988 Decommissioning Rule, 53 FR 24019.

persists, as compared to timely self-initiated compliance, based on the staff's experience with the shortfalls reported in 2003 and 2009. Consequently, case-by-case negotiation, particularly without a time guideline for completion, does not meet the NRC's safety objectives.

Second, the Commission rejected a case-by-case approach to decommissioning in its 1988 Decommissioning Rule, as stated below:

> Many licensing activities have had to be determined on a case-by-case basis. The procedure results in inconsistent dealing with licensees and in inefficient and unnecessary administrative effort. With the increased decommissioning expected, case-by-case procedures would make licensing difficult and increase NRC and licensee staff resources needed for these activities.[20]

The staff's experience with case-by-case negotiation to resolve shortfalls reported in 2009 confirmed the resource intensive nature of that approach. Resolving the shortfalls case-by-case cost over 1700 staff hours. The Commission's policy to avoid case-by-case decommissioning funding procedures should remain in place.[21]

Third, using the case-by-case approach may decrease the incentive of licensees to take timely self-initiated action. The NRC has experience with two significant equity market declines that played a role in causing shortfalls in licensee financial assurance. A case-by-case approach was used on both occasions. Table 2 below summarizes licensee performance in response to the 2003 and 2009 equity market declines. In 2003, about 91 percent of power reactors avoided shortfalls, while in 2009, about 75 percent avoided shortfalls. The number of licensees with shortfalls increased more than expected in relation to the percentage decline in the market. The number of licensees that corrected their shortfalls in 3 months decreased in 2009, although a greater number needed to make corrections. In 2009, 26 of 27 licensees with shortfalls did not provide a plan to cover the shortfall until directed to do so by the NRC.[22] In 2009, the number of licensees that resolved their shortfall within three months following the end of the reporting period on December 31 decreased from 3 to 1. Following the 2003 market decline, all licensees resolved their shortfalls within 1 year. In 2009, six licensees did not resolve their shortfalls within 1 year. The six licensees raised several issues: 4 licensees claimed the staff should accept NPV methods to calculate the size of the shortfall; 1 licensee provided an incomplete parent company guarantee; and 1 licensee provided a power sales contract which is under review by the staff. Comparing 2009 to 2003, the number of facilities with shortfalls increased by 18, of which 16 were merchant plants. The staff concluded that (1) the data indicated an apparent trend to less adequate and less timely financial assurance by licensees and (2) engaging in case-by-case negotiations appeared to be less effective in 2009.

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20 1988 Decommissioning Rule, 53 FR 24019.

21 The Commission made an exception for prematurely shutdown reactors on the grounds that each case presented unique funding challenges. See Decommissioning Funding for Prematurely Shut Down Power Reactors, Final Rule, 57 FR 30383, 30394, July 9, 1992. In addition, the NRC may take action to modify the licensee's schedule of accumulation of funds on a case-by-case basis (10 CFR 50.75(e)(2)).

22 During the summer of 2009, the NRC issued letters to 26 licensees directing them to provide a plan of action to cover the shortfalls.

Table 2. Market Decline and Numbers of Facilities with Shortfalls[23]

Reporting Year	Market Decline from Previous Report	Number of Facilities with Shortfalls	Number of Shortfalls Resolved in 3 Months	Number of Shortfalls Not Resolved in 1 Year
2003[24]	- 23%	9	3	0
2009[25]	- 30%	27	1	6

Allowing some licensees to delay fulfillment of their regulatory obligations prompted a licensee to raise a fairness question to the staff. The staff attended a recent Nuclear Decommissioning Trust Fund Study Group meeting. One licensee questioned the fairness of allowing large merchant fleet operators to avoid covering a shortfall for over a year while a State regulator requires a part owner of a power reactor to pay its share of decommissioning costs on schedule. Finally, the fact remains that three-quarters of NRC licensees successfully used forward-looking strategies that avoided shortfalls, despite the 2008 decline in equity values. Providing guidance to take timely action to cover a shortfall may encourage a larger number of licensees to use forward-looking strategies.

SUCCESSFUL HISTORY

Comment 6 Successful History Demonstrates No Changes Needed

No changes in the guidance are needed based on experience with the successful completion of decommissioning of public utility power reactors that had shortfalls in financial assurance at the time of permanent shutdown

Response 6

The historical success cited by the commenter relied heavily on the public utility status of the licensees involved. Utility licensees can normally obtain the consent of rate regulatory authorities to raise additional funds through ratepayer collections to cover their shortfalls. Merchant plant licensees have no access to ratepayer collections, so the economic basis of earlier successes does not apply to merchant plant licensees. In either case, licensee experience demonstrates that shortfalls should be covered in a timely manner to avoid financial stress that could cause a delay in decommissioning due to lack of funds.

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23 Decline calculated from Dow Jones Industrial Average Index closing price on December 31 of the relevant years

24 SECY-04-0019 summarized the case-by-case evaluations of six licensees that had shortfalls. The total number of shortfalls in 2003 was nine, since the SECY did not refer to three Progress Energy licensees that took self-initiated action to cover their shortfalls when the company submitted its 2003 decommissioning fund status report. The total number included 1 merchant and 8 utility facilities.

25 SECY-09-0416 describes the number and dollar amount of the shortfalls that occurred in 2009. The number of shortfalls not resolved in 1 year was determined by a review of the plans and associated response to requests for additional information submitted by licensees. The total number included 9 public utility facilities, 16 merchant plant facilities, and 2 facilities that were “hybrids,” with both utility and merchant licensee owners.

The CY experience illustrates three points that support the need for timely resolution of shortfalls. First, no licensee, including a public utility, enjoys immunity from competition that could significantly change its business outlook. Faced with lower priced competition, CY concluded that immediate retirement of its nuclear operation was the least-cost option for its customers. CY planned to supply its customers by purchasing power from lower priced competitors. Second, a shortfall in financial assurance can itself result in financial stress. When CY shut down, it had not yet collected adequate funds to decommission.[26] Although CY continued to receive funds through its wholesale power contracts, the large unfunded obligation reduced its credit rating below investment grade. Third, ratepayer funds were the source of success in resolving past shortfalls. In order to obtain cash when needed, CY required the consent of its rate regulator to raise additional funds from the ratepayers. These points are discussed further in the following paragraphs.

CY demonstrated the rapidity with which a licensee's economic outlook can decline, based on a relatively modest decrease in prices from competing sources of electricity. CY was regulated by the Federal Energy Regulatory Commission (FERC) as an electric wholesaler. In CY's case, the licensee's economic outlook shifted from viable to nonviable within 3 years, resulting in a decision to shut down immediately and prematurely.[27] The licensee stated in testimony before FERC that competitive pressure from lower priced sources of electricity was the only basis for the shutdown decision.[28]

CY based its decision on studies it performed from time to time to evaluate its costs of continued operation. A continued unit operation (CUO) study performed by CY in 1993 projected savings of $175 million from continued operation of the plant.[29] Three years later, an updated CUO study showed that the economic outlook had reversed. The 1996 CUO study showed that 13 of 14 scenarios produced savings for CY's customers by shutting down immediately and purchasing power from other sources to satisfy customer demand. The single scenario showing a positive return from continuing operation was considered unlikely since it assumed overly optimistic reductions in operating costs. The 1996 reference case projected savings of $53 million on a net present value (NPV) basis from retiring the plant and obtaining replacement power from other sources.[30] The reference case estimated the nominal dollar savings at $145 million for the remaining 10 years of operation.[31] In 1995, the last full year of operation, CY's electric sales revenues were $211 million.[32] On average, the projected nominal dollar savings of $14.5 million per year was about 7 percent of annual sales revenue. CY announced its permanent shutdown in December 1996. From this experience, the staff concluded that the time period to cover a shortfall in financial assurance should be not longer

26 As an electric utility, CY was allowed to collect funds for decommissioning over time in its rates.

27 Initial Decision, p. 9, 84 FERC ¶ 63009, August 31, 1998. (FERC Accession No. 19980901-0087)

28 Id.

29 Id.

30 Id.

31 Matrix of Sensitivity Scenarios CY Financial and Economic Analysis, December 4, 1996, CY Board Meeting. (FERC Accession No. 19980904-0309) The $53 million NPV loss and $145 million nominal loss are equivalent expressions of the projected savings from shutting down the plant. The NPV is lower due to discounting of future savings back to the date of the estimate. The nominal value is used to calculate the percentage of annual revenue represented by the projected savings since it simplifies the calculation.

32 Connecticut Yankee Atomic Power Company Statements of Income Revenue Data to Reflect Present Versus Proposed Rates, October 14, 1997. (FERC Accession No. 19980904-0495)

than 3 years, rather than allowing decades to make up the shortfall with market gains, as suggested by the commenter.

The CY experience provides an example of the financial stress that a large unfunded decommissioning obligation can cause when it comes due. After announcing the retirement of its nuclear operation, the licensee's credit rating was reduced to below investment grade.[33] The credit rating drop caused cash flow problems for the licensee. Although CY continued to receive payments from its power contracts, it needed accelerated payments to meet its current payment obligations. CY was owned by a consortium of 10 utilities in the Northeast, each of which was obligated to buy a share of the plant output under a power contract.[34] To obtain additional credit from its bank lenders, CY requested that FERC modify the amendatory agreements to its power contracts to allow accelerated payments in the event CY's cash flow was insufficient to meet its obligations as they came due.[35] CY stated that, without the modification, it would have defaulted on its mortgage bonds.[36]

Perhaps most importantly, the CY experience illustrates the advantage a public utility has in obtaining cash to cover shortfalls, as compared to a merchant plant licensee. The amounts obtained in rate case settlements in 2000 and 2006 are listed below. The amounts exceeded the NRC minimum formula specified in 10 CFR 50.75(c) for a number of reasons. The authorized collections provided for spent fuel storage costs and site restoration, which are not included in the NRC formula for the minimum required amount of financial assurance for decommissioning.[37] A number of site-specific factors, such as soil contamination and large legal expenses, also increased the costs. The NRC's regulations require a licensee to submit a preliminary decommissioning cost estimate about 5 years prior to the expected termination of operation. The preliminary cost estimate must include an up-to-date assessment of the major factors that could affect the cost of decommissioning.[38] In the CY case, the shutdown occurred 11 years before the operating license expiration date, so CY did not trigger the 5-year requirement to address site-specific factors. However, the amounts listed below illustrate the potential value of access to ratepayer funds, which is not available to a merchant plant licensee.

Additional CY funds authorized for 2000 to 2007 = \$133.6 million[39]
Additional CY funds authorized for 2005 to 2015 = \$504.3 million[40]

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33 Federal Energy Regulatory Commission Connecticut Yankee Atomic Power Company Direct Testimony of John B. Keane, p. 18, October 14, 1997. (FERC Accession No. 19980904-0296)

34 Id., pp. 7–8. The owners were themselves electric utilities who were also CY's customers, purchasing the output for resale.

35 Id., pp. 20–21.

36 Id. p. 22.

37 Spent fuel management costs are addressed in 10 CFR 50.54(bb). Site restoration costs are typically addressed by State rate regulators.

38 10 CFR 50.75(f))(3).

39 Letter Order, 92 FERC ¶ 61.055, July 26, 2000 (approving Offer of Settlement, p. 8, describing payments of \$16,742,000 annually from 2000 through 2007, April 7, 2000). (FERC Accession No. 200011203-0197)

40 Order Approving Uncontested Settlement, 117 FERC ¶ 61.192, November 16, 2006 (approving Rate Schedule FERC No. 11, August 15, 2006). (FERC Accession No. 20080826) Amount calculated as the difference between collections scheduled from 2004 through 2015 less previously approved collections from 2004 through 2007.

The potential size of an unfunded obligation in the event of premature shutdown, combined with the inability of a merchant plant licensee to obtain ratepayer funds to cover the expenses, was one of the reasons the Commission amended its financial assurance rules in 1998 as follows:

> For licensees that will not be able to collect funds through such a [ratemaking] process after industry restructuring, up-front assurance is necessary to ensure that reasonable financial assurance is provided for all decommissioning obligations. In the more competitive environment that is likely to prevail after restructuring, some of these licensees may not remain financially viable for reasons not related to decommissioning financial assurance, further suggesting the need for up-front assurance. [41]

The lessons learned from the CY experience apply to both electric utility and merchant plant licensees. Both categories of licensees face increased competition, although the merchant plant licensees are likely more sensitive to price pressure because they do not have an assured customer base or rates based on cost of service. Both categories face potential financial stress if they shut down with a large unfunded liability for decommissioning. Both categories face the need for additional funds if the decommissioning fund is not adequate at the time of shutdown. Although the CY experience resulted in a premature shutdown, the lesson remains valid for the expected shutdown on the license expiration date. The point here is the amount of the unfunded decommissioning obligation at shutdown, not whether the shutdown is premature. However, a merchant plant licensee faces a greater need to maintain adequate decommissioning financial assurance at all times during operation because it has no access to ratepayer funds. In addition, where a merchant plant is organized as a subsidiary of its parent company, the parent is generally not required to make up shortfalls in the subsidiary's financial assurance.[42]

The staff concluded that the Connecticut Yankee experience established an upper limit of 3 years for the period to cover a shortfall for licensees that do not have access to rate payer funds.

FINANCIAL BURDEN

Comment 7 Annual Adjustment of Financial Assurance is an Undue Financial Burden

The 1-year guideline to cover a shortfall is an undue financial burden.

Response 7

The staff disagreed for a variety of reasons that are discussed in the responses that follow. In brief, the Commission stated that the cost of financial assurance for decommissioning is not an inordinate financial burden for licensees in its 1988 Decommissioning Rule.[43] In fact, when the 1988 Decommissioning Rule was issued, power reactor licensees were required to make

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41 Financial Assurance Requirements for Decommissioning Nuclear Power Reactors, Final Rule, 63 FR 50465, 50469, September 22, 1998 (hereinafter referred to as the 1998 Decommissioning Rule).

42 It is a general principle of corporate law deeply "ingrained in our economic and legal systems" that a parent corporation (so-called because of control through ownership of another corporation's stock) is not liable for the acts of its subsidiaries. *United States v. Bestfoods*, 524 U.S. 51, 61 (1998)

43 1988 Decommissioning Rule, 53 FR 24018, 24033

annual cash contributions to their external sinking funds.[44] The staff determined that the commenter overestimated the cost of providing financial assurance to support its claim of undue burden. When the actual costs are considered, the staff concluded that the cost of covering a shortfall is within the range anticipated by the NRC when the financial assurance regulations were issued and amended. In addition, as discussed in Comment 2, "Notice-and-Comment," the frequency of annual adjustment is within the scope of the Commission's policy that a licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning.[45]

Comment 8 Letter of Credit (LOC) Fees are an Undue Financial Burden

Fees for a letter of credit impose an undue financial burden on licensees. For example, the cost of a letter of credit is approximately 4% of the assured value on an annual basis.

Response 8

In forming its response, the staff reviewed the 1998 Decommissioning Rule notification to merchant plant licensees that giving up public utility status could significantly increase the amount of financial assurance they would be required to produce. The rule stated the following:

> … the amount that would need to be assured under such a [letter of credit or surety bond] mechanism (i.e., the difference between the licensee's decommissioning cost estimate and the current balance in its external sinking fund) could in some cases be quite large.[46]

The Commission went on to explain that if a merchant plant licensee could not obtain an LOC or surety, then another mechanism would be necessary, such as a PCG, which was less costly,[47] or providing full upfront funding in a prepayment mechanism.[48] The fact that the amounts of the shortfalls in 2008 were quite large falls within the scope of the notification provided in 1998. Licensees must provide the minimum financial assurance amount even if the shortfall is quite large.

The Commission also addressed shortfalls caused by events outside the licensee's control. Under the provisions of 10 CFR 50.75(e)(1)(v), a licensee may use a power sales contract as financial assurance. The contract must require that payments will be made regardless of "force majeure" conditions that would otherwise permit the contracting parties to terminate or renegotiate the contract.[49] The NRC listed several examples of "force majeure" conditions that

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[44] See 10 CFR 50.75(e)(3)(iii) (1988), 1988 Decommissioning Rule, 53 FR 24050. At the time, all power reactors were electric utilities.

[45] Decommissioning of Nuclear Power Reactors, Final Rule, 61 FR 39278, July 29, 1996.

[46] 1998 Decommissioning Rule at 63 FR 50465, 50471.

[47] The Commission stated that the self-guarantee method eliminates the cost of third party financial assurance, such as the LOC and surety (Self-Guarantee as an Additional Financial Assurance Mechanism, Final Rule, 58 FR 68726, December 29, 1993). The self-guarantee is similar to the parent guarantee, so the same cost conclusion applies.

[48] 1998 Decommissioning Rule at 63 FR 50465, 50471.

[49] 1998 Decommissioning Rule at 63 FR 50465, 50472.

would not excuse the requirement to provide adequate financial assurance: recession, inflation, and severe market changes.[50]

To summarize the *Federal Register* statements quoted above, the NRC notified merchant plant licensees that the burden of covering a shortfall could be quite large and that a severe market change would not excuse the requirement to provide adequate financial assurance. The commenter argues that the burden of covering the shortfalls is largely due to a severe market decline. That argument falls within the scope of shortfalls that must be covered, as described in the *Federal Register.* Consequently, the burden of covering a large shortfall caused by a market decline, similar to the situation in 2009, has been evaluated and determined to be necessary to ensure adequate assurance that funds for decommissioning will be available when needed.

The staff is not aware of a power reactor licensee that currently uses an LOC for nuclear decommissioning financial assurance. However, to gain insight on the use of the method, the staff reviewed the use of LOCs by parent company owners of power reactors. The staff found that some large power reactor fleet owners use large amounts of LOCs for many purposes unrelated to nuclear decommissioning. For example, Florida Power and Light (FPL) uses LOCs to guarantee obligations in the amount of $737 million.[51] FirstEnergy Corp. uses LOCs in the amount of $2.1 billion.[52] The staff concluded that the LOC is a viable method to guarantee a future obligation.

In addition, the staff compared the commenter's estimated cost of an LOC of 4 percent per year with other sources of information. The staff found many sources indicating that the commenter had overestimated the cost. Historically, the staff found that the fee for an LOC has been around 1.5 percent per annum. For example, in a final rule issued in 1993, the NRC reported that, for licensees other than power reactors, annual fees for LOCs, surety bonds, and other forms of third party financial assurance typically are approximately 1.5 percent of the amount of financial assurance provided.[53] FirstEnergy Corp. reported that annual fees for its LOCs ranged from 0.35 percent to 1.70 percent as of 2008.[54] A materials licensee, with revenues and decommissioning obligations comparable to a power reactor owner, recently reported that the cost for an LOC was about 1 percent of the face value. However, that licensee found that a surety would be even less costly and opted to use the surety method of providing financial assurance with an annual fee of 0.75 percent. Considering all sources surveyed, the staff found that the range of fees for an LOC was 0.35 percent to 2.5 percent.[55] The high end of the range

50 Id., Footnote 1.

51 FPL Group, Inc., Florida Power and Light, Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, Form 10-Q, p. 38, September 30, 2009 (hereinafter referred to as FPL 2009 Form 10-K).

52 FirstEnergy Corporation, 2008 Annual Report, p. 96.

53 Self-Guarantee as an Additional Financial Assurance Mechanism, Final Rule, 58 FR 68726, December 29, 1993.

54 FirstEnergy Corporation, 2008 Annual Report, p. 96.

55 A nonpower reactor applicant reported in March 2010 that it would obtain an LOC for a 2-percent fee (Personal communication, C. Montgomery, Project Manager, NRC). EnergySolutions reported the cost for an LOC at 2.5 percent (EnergySolutions, Form 10-K, Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, p. 72, February 27, 2009). McDermott, Inc., which owns a fuel fabrication facility, reported fees of 1.125 percent to 1.875 percent for its LOCs (McDermott International, Inc., Form 10-K, Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, p. 52). US Bank

was reported by companies with much smaller revenues and assets than power reactor fleet owners. The staff concluded that a range from 0.35 to 1.7 percent is a reasonable estimate for power reactor licensees. The staff used that range to estimate the cost of covering the 2009 shortfalls using an LOC. The 2009 shortfalls totaled $2.4 billion.[56] Twenty-seven facilities operated by six parent companies fell short of the regulatory requirement.[57] Of the 27 facilities, 26 did not resolve their shortfalls within 3 months. The combined annual revenue of the six parent companies was $93 billion, and their combined net income was $6.2 billion.[58] For the industry, the staff estimated that the tax-adjusted cost of using an LOC to cover the shortfall would have been between $5.5 million and $27 million. The range of cost per reactor, using an LOC, was calculated from the reactors with the lowest and highest shortfalls. The cost estimates for the three guarantee methods are presented in Table 3 for the 26 facilities that did not resolve their shortfalls within 3 months. The actual cost would likely have been lower, since many licensees resolved their shortfalls using other methods in less than a year and could have dropped the LOC or surety.

Table 3. Estimated Cost for 26 Licensees To Cover Shortfalls Reported in 2009

Item	Guaranty Mechanism			
	Letter of credit		Surety	PCG[59]
Cost, % of Face Value	0.35	1.7	0.75	0
Industry cost	$8.4 million	$41 million	$18 million	$0
Tax-adjusted industry cost[60]	$5.5 million	$27 million	$12 million	$0
Tax-adjusted industry cost as % of annual revenue	0.006	0.029	0.013	0
Tax-adjusted industry cost as % of net income	0.09	0.44	0.19	0
Range of shortfalls per reactor	$500,000–$199 million	Same	Same	Same
Tax-adjusted cost per reactor	$1,100 to $455,000	$5,500 to $2.2 million	$2,400 to $975,000	$0

Comment 9 Fees for a LOC May Increase in Negative Markets

Fees for a letter of credit may increase in a strongly negative market, such as the one experienced in 2008. A letter of credit may not be available during strongly negative market conditions

stated that it charged an LOC fee of 1 percent for firms with investment grade credit rating, with a carrying charge of 0.4 percent per year for a standby LOC (Personal communication, P. Fredrichs, US Bank).

56 SECY-09-0146, "2009 Summary of Decommissioning Funding Status Reports for Nuclear Power Reactors," p. 7, October 6, 2009. (ADAMS Accession No. ML092580041)

57 Id., p. 6.

58 Sums calculated from annual reports to shareholders and SEC Form 10-K.

59 Licensees that have no parent company cannot use the PCG. However, they could use a self-guarantee, which has a more stringent financial test, but no financing costs.

60 35-percent corporate tax rate (Publication 542, Corporations, p. 17, U.S. Internal Revenue Service).

Response 9

The staff's survey of costs for LOCs included the 2008 time period, as discussed in the response to Comment 8, "Letter of Credit (LOC) Fees are an Undue Financial Burden." The costs were a very small percentage of the resources of the parent companies that own power reactors. The available information did not indicate whether those costs had increased from earlier periods.

However, licensees have the ability to make forward-looking plans to address the inescapable volatility of the equity markets. A commercial firm typically arranges for credit facilities to assure access to funds and credit when needed. Using its credit facilities, a firm has the ability to make a forward looking plan to ensure the future availability of and reasonable pricing for LOCs. For example, FPL Group, Inc., which owns a number of power reactor licensees, reported that its credit facility provided access up to $6.4 billion worth of LOCs.[61] In addition, the NRC provides flexibility in the methods allowed for providing financial assurance. Licensees that face potentially higher than average LOC costs have the ability to use other methods.

In view of the above, the staff did not agree that the potential increased cost and difficulty of obtaining an LOC after a market decline justifies a delay in covering a shortfall.

Comment 10 The Parent Company Guarantee (PCG) Imposes Significant Costs

A parent company guarantee imposes significant indirect costs due to its prohibition on using the pledged assets as collateral for any other obligation, which can lead to credit stress, possibly even a ratings downgrade. For example, providing a PCG for $300 million could result in significant adverse financial consequences due to the requirement to set aside assets worth at least six times the amount guaranteed, and a prohibition on pledging the set-aside assets as collateral for other any other obligation.

Response 10

The staff concluded that the commenter overestimated the indirect cost of the PCG due to misunderstanding the provisions of Appendix A to 10 CFR Part 30, which governs the PCG. However, the staff reviewed an extensive body of information to verify that the PCG did not impose indirect costs on the parent company.

The PCG is simply an agreement between a parent company and its licensee subsidiary.[62] Under the terms of the PCG, the parent agrees to pay funds into the decommissioning trust, up to the face amount of the PCG, if the licensee fails to meet its decommissioning obligation. It has no financing costs, and the commenter did not assert any.[63] Licensees that have no parent

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61 FPL Group, Inc. 2009 Annual Report, p.93

62 Revision 1 to RG 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," p. 57, October 2003.

63 The NRC stated that the self-guarantee, which is similar to the PCG, was provided as a financial assurance mechanism, in part, on the basis that it would eliminate the financing cost of third party methods, such as an LOC, insurance, or a surety. See 58 FR 68726. The self-guarantee requires a higher credit rating ("A") and greater assets (10 times the amount guaranteed) than a PCG. See Appendix C, "Criteria Related to Use of Financial Tests and Self Guarantees for Providing Reasonable Assurance of Funds for Decommissioning," to 10 CFR Part 30.

company cannot use the PCG.[64] However, those licensees may use the self-guarantee, which is very similar, but has a more stringent financial test.[65] The evaluation of costs described below applies equally to the PCG and the self-guarantee.

The staff disagreed that the PCG imposed indirect costs via "setting aside" assets that would otherwise be available to serve as collateral for other obligations. The commenter cited NRC regulations as the basis of its statement. However, the commenter misunderstood Appendix A to 10 CFR Part 30, which governs the PCG. The regulation imposes a financial test which requires the parent company to "have" an investment grade bond rating, tangible net worth at least six times the amount guaranteed, and assets located in the United States with a value at least six times the amount guaranteed.[66] The regulation does not require the parent company to set aside any assets and it places no restriction on using the parent's assets as collateral for any other purpose. The NRC provides regulatory guidance on PCGs in RG 1.159 and NUREG-1577, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance," Volume 3. The guidance contains model language for the PCG agreement that must be submitted to the NRC to implement the regulations of Appendix A to 10 CFR Part 30. The PCG agreement recites the financial test criteria of the regulation and states the amount the parent will provide in the event the licensee fails to perform its required decommissioning activities. The PCG agreement does not impose a requirement to set any funds aside in anticipation of a default by the licensee, and it does not restrict the parent company's use of its funds in any way. The staff concluded that neither the regulation nor the regulatory guidance contained any restrictions on the use of the parent company's assets that would impose the indirect costs asserted by the commenter.

The regulatory history of the PCG supports the staff's conclusion that the PCG method does not impose indirect costs. The NRC added the PCG method at the request of licensees for materials and research and test reactors when it issued the original financial assurance rules in 1988.[67] The NRC issued the PCG rule on the basis that it would minimize impacts on licensees.[68] Later, in 1998, the NRC extended the use of the PCG to power reactors in response to a comment requesting that action.[69] None of the comments received in response to either of the NRC rulemakings made a claim that indirect costs would make the PCG unworkable. Similarly, the U.S. Environmental Protection Agency (EPA) has allowed PCGs as financial assurance for environmental cleanup obligations.[70] The EPA did not receive comments in its rulemaking activities that claimed the PCG imposed indirect costs.[71]

The staff reviewed relevant accounting standards to determine whether accounting practices might impose indirect costs not previously considered by the NRC. The staff found no previously unconsidered indirect costs. Accounting for decommissioning costs is specified

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64 Appendix A to 10 CFR Part 30.

65 Appendix C to 10 CFR Part 30.

66 An alternate financial test the licensee may choose does not require an investment grade bond rating, but adds two requirements: (1) to meet certain financial ratios and (2) to have net working capital worth at least six times the amount guaranteed. No licensee currently uses this alternate test to qualify for the PCG.

67 1988 Decommissioning Rule, 53 FR 24018, 24034.

68 1988 Decommissioning Rule, 53 FR 24018, 24035.

69 63 FR 50465, 50470–71, September 22, 1998.

70 40 CFR 264.143(f).

71 Personal communication, P. Bailey, ICF Consulting. Mr. Bailey has extensive experience with the NRC and EPA financial assurance regulations. He has provided consulting services to the NRC on many occasions.

under Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143).[72] The standard arose from a request from the Edison Electric Institute to the Financial Accounting Standards Board (FASB) to address accounting for the costs of nuclear decommissioning, as well as similar costs incurred in other industries.[73] FASB issued SFAS 143 in 2001, to be effective for fiscal years beginning after June 15, 2002.[74] The standards in SFAS 143 require a company to record its decommissioning liability on its balance sheet using specific procedures based on the amount of the decommissioning cost, the time when the costs will be incurred, and the company's borrowing rate. The relevant point is that the PCG does not affect the size of the decommissioning liability, its timing, or the parent's borrowing rate, so using a PCG does not affect the asset retirement accounting procedures.

FASB established a specific standard to define the disclosure requirements for corporate guarantees in FASB Interpretation No. 45 (FIN No. 45), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," issued in November 2002. FIN No. 45 states that guarantees issued between a parent company and its subsidiary are not required to be recognized as a liability on the balance sheet.[75] The PCG fits into the exception established by FIN No. 45, therefore, it is not required to be recorded on the balance sheet as a liability. For example, in its 2004 Annual Report, Progress Energy disclosed that it used PCGs for nuclear decommissioning in a section titled, "Off-Balance Sheet Arrangements and Contractual Obligations."[76] The PCG is off the balance sheet because it is not recorded as a liability. In view of this, the staff concluded that the relevant accounting standards do not impose indirect costs of the type asserted by the commenter.

The staff reviewed financial reports from three licensee parent companies to verify its conclusion. In the following examples, the parent companies used LOCs and parent guarantees with very large dollar amounts for many purposes. PCGs used for nuclear decommissioning were a small percentage of the total.

The first example involves Duane Arnold, which used a $93 million PCG provided by its parent, FPL Group, as part of its decommissioning financial assurance. FPL Group disclosed the PCG in its September 2009 Quarter Report, in a note titled, "Guarantees and Letters of Credit," which stated the following:

> FPL Group and FPL obtain letters of credit and issue guarantees to facilitate commercial transactions with third parties and financings. Letters of credit and guarantees support, among other things, the buying and selling of wholesale energy commodities, debt and related reserves, capital expenditures for wind development, nuclear activities, the commercial paper program of FPL's consolidated VIE from which it leases nuclear fuel and other contractual agreements. Each of FPL Group and FPL believe it is unlikely that it would incur any liabilities associated with the letters of credit and guarantees. Accordingly, at

72 R. Schroeder, S. Sevin, K. Yarbrough, "Reporting Effects of SFAS 143 on Nuclear Decommissioning Costs," *Int'l Advances in Econ. Res.*, Vol. 11, p. 450, 2005.
73 SFAS 143, p. 24, June 2001.
74 Id. p. 6.
75 FIN No. 45, p. 4.
76 Progress Energy 2004 Annual Report, p. 43.

> September 30, 2009, FPL Group and FPL did not have any liabilities recorded for these letters of credit and guarantees.[77]

As of September 2009, FPL Group had LOCs totaling $737 million and guarantees with a notional amount of $9.6 billion.[78] The $93 million PCG provided for Duane Arnold was a small amount compared to the total amount of guarantees issued by FPL Group. Note that, despite the large total amount of the guarantees, FPL Group did not record them on its balance sheet. Disclosing such guarantees without recognizing them as liabilities on the balance sheet is consistent with FIN No. 45, as discussed above. FPL Group reported that it received credit ratings of "A" or better by the three major credit rating agencies.[79] The disclosures and credit ratings reported by FPL Group contradict the commenter's assertion that use of a PCG is likely to result in credit stress and possible credit rating downgrading.

FirstEnergy Corp., owner of Beaver Valley, provided a second example of a parent company with large amounts of LOCs and parent guarantees. In 2008, FirstEnergy Corp. used $2.1 billion in LOCs[80] and, including its subsidiaries, provided $3.8 billion in guarantees.[81] At the time, FirstEnergy Corp. used an $80 million PCG for Beaver Valley.[82] The Beaver Valley PCG is small compared to the total amount of guarantees. In addition, FirstEnergy Corp. made the following statement:

> We believe the likelihood is remote that such parental guarantees will increase amounts otherwise paid by us to meet our obligations incurred in connection with ongoing energy and energy-related activities.[83]

When reading the FirstEnergy Corp. statement quoted above, the word "remote" is a term of art in accounting use. A loss contingency classified as "remote" is defined as one with only a slight chance of occurring.[84] Accordingly, it does not require recognition on the balance sheet as an accrued liability.[85]

FirstEnergy Corp.'s credit ratings also contradict the commenter's assertion that using PCGs leads to potential credit downgrading. In fact, Standard and Poor's changed its outlook for FirstEnergy Corp. from "negative" to "stable" and upgraded the credit rating of several of FirstEnergy Corp.'s subsidiaries from BBB- to BBB.[86] The upgrading occurred during a period when FirstEnergy Corp. carried $5.9 billion in LOCs and parent guarantees.

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77 FPL Group, Inc. Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, 2009 Form 10-Q, p. 38, September 30, 2009. [Hereinafter FPL 2009 Form 10-Q]

78 Id.

79 FPL 2009 Form 10-Q, p. 38

80 FirstEnergy Corp., 2008 Annual Report, p. 96.

81 FirstEnergy Corp., 2008 Annual Report, p. 37.

82 Id.

83 Id.

84 Preliminary Summary of Financial Accounting Standards for Environmental Liabilities, Intangible Assets and Climate Change Risk, Draft Report, U.S. Environmental Protection Agency, p. 12, April 28, 2008. Available at http://www.epa.gov.

85 Id., p. 13.

86 FirstEnergy Corp., 2008 Annual Report, p. 35.

The staff reviewed a third example where three power reactor licensees used the PCG as a timely, minimal cost method for providing temporary financial assurance in response to an equity market decline. Progress Energy, which owns electric utility licensees, demonstrated the PCG's usefulness in its March 28, 2003, biennial decommissioning fund status report. A licensee must determine the status of its decommissioning fund as of December 31 of each even numbered year and file a report by the following March 31, although in certain circumstances the licensee must submit the report annually. Progress Energy informed the NRC that the decommissioning trust fund balances for three of its public utility reactors (Robinson 2, Brunswick 1 and 2) did not cover the minimum required amount specified in 10 CFR 50.75(c), as stated below:

> However, in order to provide an amount at least equal to the estimated decommissioning costs for each of those facilities, the trust funds are being combined with parent company guarantees, pursuant to 10 CFR 50.75(e)(1)(iii)(B), as identified on Attachments 1, 2, and 3. The financial tests required by 10 CFR 30, Appendix A, and other documents recommended by draft Regulatory Guide 1106 to support the guarantee are enclosed.
>
> The use of the parent company guarantees is considered an interim measure for maintaining compliance with the regulations. The reactors identified in Attachments 1, 2, and 3 are currently at different stages in the license renewal process. When issued, license renewal is expected to improve the status of the respective trust fund. If the status of a trust fund improves such that financial assurance of decommissioning funds can be established without the use of the associated parent company guarantee, PEC plans to terminate the associated parent company guarantee, as permitted by the regulations.[87]

The shortfalls resulted from a decline in the equity markets.[88] The amount guaranteed for the three reactors was $276 million,[89] which is very close to the $300 million NEI asserted would cause financial stress and credit rating downgrading. In fact, Progress Energy's credit ratings were downgraded, although for reasons unrelated to the PCGs issued to cover the shortfalls. Progress Energy stated that its credit ratings had been downgraded due to the slower-than-planned pace of its efforts to pay down debt from its acquisition of Florida Progress.[90] However, in contradiction to the commenter's assertion of the consequences of credit downgrading, the company stated that it remained in the investment grade category, and that the downgrades had not materially affected its access to liquidity or the cost of its short-term borrowings. In accordance with FIN No. 45, the PCGs were not recorded as liabilities on the balance sheet.[91]

The staff drew several conclusions from the Progress Energy experience. First, the use of a PCG as a temporary measure to cover a shortfall is a proven technique. Second, a licensee has the ability to provide PCGs to cover shortfalls within 3 months. Third, even in a case in

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87 Letter, Biennial Decommissioning Funding Status Report and Notification of Change in Decommissioning Funding Method, p. 2, March 28, 2003. (ADAMS Accession No. ML030970280)

88 Progress Energy 2003 Annual Report, p. 35.

89 Progress Energy 2003 Annual Report, p. 87. Progress Energy had $1,057 million of parental guarantees outstanding at the time, including the $276 million for nuclear decommissioning. Progress Energy was authorized by its rate regulator to issue up to $3 billion in guarantees (Id., p. 36).

90 Progress Energy 2003 Annual Report, p. 38.

91 Progress Energy 2004 Annual Report, p. 43.

which a credit downgrading occurs, a licensee does not necessarily experience liquidity difficulties or higher short-term borrowing costs. Fourth, a licensee anticipating license renewal can cover a shortfall with a PCG until the renewal application is resolved. Finally, it appears there are no financial reasons to avoid using a PCG to cover a shortfall, if the parent can pass the NRC's financial test.

New reactor applications also contradict the commenter's assertion that PCGs in the range of $300 million impose significant indirect costs on a licensee. The combined license application for the Bell Bend Nuclear Power Plant stated that it would provide a PCG in the amount of $398.6 million. The applicant did not identify any potential financial stress caused by indirect costs from its planned use of the PCG.[92]

As another check, the NRC staff discussed the effect of a PCG on a company's financial statements with the staff of the Securities and Exchange Commission (SEC). The SEC has authority under Section 19 of the Securities Act of 1933 to establish generally accepted accounting procedures for public companies.[93] SEC staff stated that using a PCG would not be expected to result in credit downgrading or reduced liquidity.[94]

The staff also contacted Moody's Investor Services, one of the three major credit rating agencies in the United States. The Moody's analyst had personal knowledge of the methods used to develop the ratings for large parent companies that own nuclear reactors. The analyst stated that parent company guarantees (PCGs) are considered when developing a rating for a company. But, when a guarantee is contingent with little likelihood of performance, it normally has little weight in the rating. The staff noted that the PCG allowed by the NRC is a contingent agreement because the PCG does not require performance on the part of the parent company unless the licensee subsidiary is not able to provide funds when needed for decommissioning. However, NRC regulations require a licensee subsidiary to accumulate full funding of decommissioning costs by the time of permanent shutdown, so the expectation is that the PCG provided for decommissioning financial assurance would not normally require performance. The analyst stated that a PCG of that nature would not normally be expected to affect the liquidity analysis or credit rating of the parent company, in view of the assets and cash flow of companies that operate power reactors for electricity production.[95]

In view of the above information, the staff concluded that the direct and indirect costs to a licensee using a PCG are minimal and are not an undue financial burden.

Comment 11 NRC Should Allow More than 3 Months to Cover a Shortfall

Covering a shortfall in the 3-month timeframe between the end of the decommissioning fund status reporting period on December 31 and the fund status report due date on the following March 31 could result in higher costs and diversion of resources from operating plants.

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92 Bell Bend Nuclear Power Plant Combined License Application, Part 1: General and Administrative Information, Revision 1, p. 1-11, February 27, 2009. (ADAMS Accession No. ML090710465)

93 William W. Bratton, *Private Standards, Public Governance: A New Look At The Financial Accounting Standards Board*, p. 7, *Boston College L. Rev*. Vol. 48:1, January 2007.

94 Personal communication, A. Simmons, NRC attendee at the SEC meeting.

95 Personal communication, T. Fredrichs, US NRC.

Response 11

A licensee has the ability to make forward-looking plans to meet the decommissioning financial assurance requirements before the December 31 recalculation of the minimum requirement for decommissioning. As noted in Comment 10, "The Parent Company Guarantee (PCG) Imposes Significant Costs," Progress Energy's experience demonstrated that 3 months provide sufficient time to cover a shortfall without adverse impacts to a company's liquidity or short-term borrowing costs. If a PCG is used, no costs are incurred. Using an LOC or a surety, the costs are a very small percentage of the resources available to the licensee. Where the licensee uses a forward looking plan to arrange a credit facility to issue LOCs, an LOC can be obtained within 3 months. Using either method, no diversion of resources from an operating plant would be necessary. In view of this information, the staff concluded that the cost of covering a shortfall within 3 months did not justify a delay in covering a shortfall.

Comment 12 Impact on Immediate Priorities

Additional funds placed in the decommissioning trust to cover a shortfall could possibly impact more immediate priorities, which places an undue burden on the licensee.

Response 12

The staff disagreed with this comment for two reasons.

First, the regulations do not specify the timing of adding funds to the decommissioning trust. As discussed above, a licensee may select from a variety of methods to provide financial assurance at reasonable cost. That flexibility allows the licensee to control the timing of making contributions to its decommissioning fund as necessary. No undue burden exists with respect to the timing of cash contributions to the decommissioning trust.

Second, the staff disagreed on the grounds that the NRC found that requiring annual contributions to the decommissioning trust was not an undue burden when it issued the 1988 Decommissioning Rule. In particular, at that time, the NRC compared the cost of requiring annual cash deposits with the cost of keeping an internal reserve as a financial assurance method.

The NRC recognized that the cost of placing funds in a prepaid account or an external sinking fund was more expensive than allowing the licensee to hold the funds in an internal reserve.[96] However, the NRC rejected the use of an internal reserve, despite its lower apparent expense. In doing so, the NRC listed several reasons for concluding that the cost of paying into a prepaid account or an external sinking fund was not an inordinate financial burden on the licensee.[97] First, an external sinking fund could be collected over time.[98] That remains true for utility licensees. Merchant plant licensees can also use an external sinking fund, if combined with a PCG, to effectively gain the same advantage allowed to utility licensees. Second, the favorable tax treatment of decommissioning trust funds reduces the cost differential between the external

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96 50 FR 5600, 5608, Decommissioning Criteria for Nuclear Facilities, Proposed Rule, February 11, 1985.

97 1988 Decommissioning Rule, 53 FR 24018, 24033.

98 Id.

sinking fund and an internal reserve.[99] Third, many licensees engage in diversified financial activities which involve more financial risk, and it is increasingly important that decommissioning funds be provided on a more assured basis.[100] Fourth, in the event of bankruptcy, there is not reasonable assurance that internal reserves can be effectively protected from the claims of creditors.[101]

The staff concluded that the reasons listed in 1988 remain valid today for concluding that cash payments into a prepaid fund or external sinking fund are not an undue financial burden.

Comment 13 Annual Adjustments Invite Poor Investment Behavior

Requiring adjustments over a short period of time could invite poor fund investment behavior, such as seeking higher risk, short-term investments to increase near-term earnings and regain liquidity tied up in PCGs.

Response 13

The staff disagreed that requiring a licensee to cover a shortfall could result in poor investment behavior, regardless of the time period allowed for adjustments.

The NRC regulations impose a number of safeguards prohibiting poor investment behavior on the part of merchant plant licensees.[102] First, the trust agreement must specify that the fund manager will follow, at a minimum, a prudent investor standard of care. The trust may not be amended in any material respect, such as the standard of care requirement, without written notification to, and absence of objection from, the NRC. The licensee is prohibited from engaging in the day-to-day management direction of the fund, except for passive investments tracking market indices. The safeguards placed on fund management prevent poor fund investment behavior such as seeking higher risk, short-term investments.

The staff disagreed that regaining liquidity tied up in PCGs could serve as a rational incentive to engage in poor investment behavior. The discussion of the PCG above demonstrates that the PCG does not tie up funds and does not decrease liquidity.

Finally, the fact remains that three-quarters of NRC licensees used financial assurance strategies that avoided shortfalls in 2009. The performance of the large majority of licensees demonstrates that a licensee has the ability to make forward-looking plans to ensure adequate financial assurance at any time during the life of the facility. Establishing and using a forward-looking plan will remove the incentive to engage in risky fund investment behavior for short-term gains. Providing guidance to cover a shortfall on an annual frequency should encourage licensees to adopt forward-looking plans that avoid shortfalls, rather than relying on market growth to make up the shortfall.

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99 Id.

100 Id. The potential risk of diversified financial activities may be more relevant today then in 1988.

101 Id.

102 10 CFR 50.75(h)(1) imposes the conditions on merchant plant trust funds. The NRC did not impose similar conditions on public utility licensee trust funds on the grounds that NRC oversight was not necessary because rate regulators exercised authority over the funds. See Decommissioning Trust Provisions, Final Rule, 67 FR 78332, 78333, December 24, 2002.

Comment 14 Licensees Should Have as Much Flexibility as Pension Fund Managers

Licensees require flexibility to manage long-term investments during periods of market crisis, analogous to the Congressional reduction of funding targets for pensions in the Worker, Retiree, and Employer Recovery Act of 2008, which reduced the mandatory minimum contributions required of employer-provided pension fund plans.

Response 14

The staff disagreed that the Worker, Retiree, and Employer Recovery Act (WRERA) of 2008 offers a relevant analogy to NRC licensees.

The basis of Congressional action in the WRERA of 2008 was to avoid job losses that could have occurred if cash-strapped employers were required to make large mandatory contributions to their pension funds. During the discussions with NRC licensees in the summer of 2009, no licensee claimed that it would experience job losses as a result of covering the shortfalls in financial assurance. To the extent that the WRERA was motivated by the desire to save jobs, it has no relevance to NRC licensees.

Likewise, the method used by the WRERA of 2008 has no relevance to NRC licensees. The method selected by Congress to implement the goal of the WRERA was to reduce the size of mandatory contributions to the pension funds.[103] In contrast, the NRC does not require mandatory contributions into decommissioning funds.[104] Under NRC regulations, a licensee has the flexibility to choose cash contributions or noncash guarantee methods to provide financial assurance for decommissioning. That flexibility allows the licensee to manage its cash flows as necessary in a market crisis without seeking relaxation of the decommissioning funding requirements. Therefore, the mechanism used by the WRERA is irrelevant to NRC licensees.

However, additional factors contradict the commenter's argument that employers managing pension funds enjoy greater flexibility than NRC licensees possess in managing decommissioning financial assurance. Pension funding is subject to an extensive regulatory system that provides assurances and penalties that are not part of the NRC's system. The commenter engaged in cherry-picking by singling out a favorable provision while ignoring the disfavored provisions. Two examples of pension funding protections that offset the risk of a temporary reduction in pension fund contributions will further demonstrate the inaptness of the analogy offered by the commenter.[105] The most significant protection for pension funding is the Pension Benefit Guaranty Corporation (PBGC), which provides insurance to cover shortfalls in pension funds.[106] Employers must pay the insurance premiums.[107] A second significant

103 Technical Explanation of H.R. 7327, "Worker, Retiree, And Employer Recovery Act Of 2008," As Passed By The House On December 10, 2008, Joint Committee on Taxation, pp. 28–29, December 11, 2008 (hereinafter referred to as Technical Explanation of H.R. 7327). Available at http://www.dol.gov/ebsa/pdf/HR7327JCTTechnicalExplanation.pdf.

104 However, 10 CFR 50.75(e)(2) authorizes the NRC to modify a licensee's schedule for accumulation of funds.

105 In the WRERA of 2008, Congress temporarily reduced the funding targets for pension funds according to the following schedule: 94 percent for 2008, 96 percent for 2009, and 98 percent for 2010. See Technical Explanation of H.R. 7327, The "Worker, Retiree, And Employer Recovery Act Of 2008," As Passed By The House On December 10, 2008, Joint Committee on Taxation, Dec. 11, 2008, p.29, *available at* http://www.dol.gov/ebsa/pdf/HR7327JCTTechnicalExplanation.pdf

106 61 FR 39278

protection requires the imposition of liens against the employer's property for failing to make timely contributions to the pension plan. When the shortfall in a pension fund exceeds $1 million, the pension statutes provide that a lien in favor of the plan shall be placed on the employer's property in the amount of the unpaid balance.[108]

As a final point, the flexibility permitted by the NRC's regulations already provide greater flexibility than allowed under pension funding rules. NRC licensee may choose from a variety of financial assurance methods in addition to making cash deposits into a trust fund. The NRC provides three methods of non-cash guarantee methods, and allows credits for future collections and earnings. This flexibility allows NRC licensees to manage their cash flows in a manner that best serves their needs while still providing adequate financial assurance for decommissioning. In contrast, the pension funds have only one option—to set funds aside in trust.[109]

In view of the above discussion, the NRC's regulations already permit its licensees adequate flexibility to adjust contributions to decommissioning trust funds as needed, as long as the required minimum is maintained using some combination of approved methods.

Comment 15 Cash Contributions Cause Overfunding

Making a cash contribution to the decommissioning trust after a market decline will result in overfunding when the market recovers.

Response 15

The commenter confused funding with financial assurance.

"Funding" refers to the actual amount of funds available for decommissioning. A fully-funded decommissioning trust would have a balance that meets or exceeds the minimum required amount of 10 CFR 50.75(c). Until a fund is fully-funded, it cannot be overfunded. The distinction will be clearer by understanding the several components that make up the amount of financial assurance provided by a licensee.

"Financial assurance" refers to the system of regulation used by the NRC to assure that funds are available when needed for decommissioning. It also refers to the total amount of assurance provided using one or more of the methods specified in 10 CFR 50.75(e). When referring to the total amount of financial assurance, it is the sum of funds accumulated in a segregated account outside the licensee's control plus the amount of any guarantees provided; plus the projected amounts of earnings on the accumulated funds; plus projected ratepayer collections by utilities; plus projected nonbypassable charges authorized by a rate regulatory agency; plus, for Government licensees, the amount provided by a statement of intent; plus projected payments from certain contractual obligations that meet NRC requirements; plus projected earnings on collections, payments, and nonbypassable charges. If applicable, financial assurance may include other methods, if the NRC determines that they provide a level of assurance equivalent to the methods of 10 CFR 50.75(e). However, in contrast to the amount of funding, a licensee is

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107 General FAQs about PBGC. Available at http://www.pbgc.gov/about/wrfaqs.html.
108 Employee Retirement Income Security Act of 1974, as amended, Section 303(k).
109 Eric D. Chason, "Outlawing Pension-Funding Shortfalls," p. 520, *Va. Tax Rev.*, Vol. 26, 2007.

required to provide financial assurance at all times during the life of the facility, through termination of the license, that adequate funds will be available to complete decommissioning.[110]

Until the trust accumulates enough funds to pay for decommissioning, it is underfunded in the sense that the available funds are less than the amount needed to pay for decommissioning. However, when the earnings credit is added to an underfunded trust, the sum may exceed the amount needed for decommissioning. Thus, when the market recovers, the trust may become "overassured" while remaining "underfunded." If the licensee elects to use cash contributions to cover the shortfall, a market recovery could yield an overassured result, but would provide the advantage of increasing the likelihood that full funding will be achieved at the time of termination of operations. In addition, cash contributions reduce the vulnerability of the fund to market volatility, which strengthens the licensee's ability to avoid future shortfalls. Alternatively, if the licensee wanted to preserve cash for other purposes, it could use a guarantee method to provide assurance in an amount no larger than necessary to cover the shortfall. If the market increases, the licensee can then discontinue the guarantee. In either case, the staff concluded that the potential for overassurance did not justify a delay in covering a shortfall.

Comment 16 Annual Adjustments Would Impose Unnecessary Premiums

If the proposed guidance were applied to the 2009 decommissioning status report, the NRC would effectively be forcing utilities to pay an unnecessary premium for decommissioning funds that will not be used for decades. To illustrate this point, the funds for those merchant nuclear plants that were identified as having shortfalls as of December 31, 2008, have collectively increased in value by well over $300 million through July 2009 with no action on the part of licensees.

Response 16

The commenter argues from hindsight. Looking backward to calculate the amount the market recovered, as the commenter did, misses the mark. When the licensees submitted their decommissioning fund status reports on March 31, 2009, no one could predict, looking forward, when or if the market would recover its value. The commenter attempts to justify delay in covering a shortfall by looking backward and observing that the actual market recovery produced gains without taking any action. However, trying to justify delay in covering a shortfall by claiming the market will "really" increase greater than the 2-percent real rate of return was discussed and rejected in Response 18.

At the same time, the commenter misses the obvious question of what might have happened if the licensees had followed the existing guidance. RG 1.159 currently provides guidance to make needed adjustments in conjunction with the decommissioning fund status report that is required by March 31 of odd numbered years. As noted earlier, 26 of 27 licensees did not resolve their shortfalls as of March 31, 2009. The staff estimated the gain that could have been realized if the merchant plant licensees referenced by the commenter had increased the investments held in their trust funds on March 31, 2009, when they submitted their decommissioning fund status reports. The Dow Jones Industrial Average increased about 20

110 Decommissioning of Nuclear Power Reactors, Final Rule, 61 FR 39278, July 29, 1996.

percent from the end of March to the end of July 2009.[111] If the merchant licensees had covered their shortfalls by investing cash in their trust funds on March 31, 2009, they could have earned 20 percent on an additional $1.7 billion, or about $340 million.[112] The gain would have been in addition to the $300 million in recovery reported by the commenter for the no action strategy used by the licensees. The staff concluded that the merchant plant licensees could have earned more than double their actual gain if they had followed the existing guidance.

Of course, the staff calculation suffers from the same hindsight error that the commenter employed. The point is that no one can predict the direction or timing of the market looking forward. Therefore, licensees should make forward-looking plans that take market volatility into account. As discussed earlier, the NRC regulations allow the use of guaranty methods with minimal cost to provide financial assurance in cases in which the licensee wants to preserve cash. Therefore, the staff concluded that the potential for market recovery does not justify delay in covering a shortfall.

INVESTMENT HORIZON

Comment 17 License Renewal Adds 20 Years to Accumulate Funds

The current business outlook makes it likely that most power reactors will have an additional 20 year time horizon to accumulate funds by obtaining license renewal.

Response 17

The staff disagreed that the availability of license renewal provides an extra 20 years to accumulate funds. License renewal merely provides the option of continued operation; it provides no guarantee that operation will actually continue. In support of that position, the staff noted that since the License Renewal Rule was issued in 1991,[113] eight power reactors have permanently shut down without applying for license renewal.[114] The commenter conceded the potential that a reactor may not seek license renewal in his statement the "most" reactors will "likely" obtain license renewal. Until a license has actually been renewed by the NRC, the potential added time horizon remains speculative, which does not justify a delay in covering a shortfall in decommissioning financial assurance.

Comment 18 Investments Will Grow to Fulfill Decommissioning Obligations

Decommissioning funds are long-term investments that will grow over time to fulfill a future obligation. For example, SAFSTOR provides up to 60 years to accumulate funds. It is unnecessary to cover a shortfall on a short-term basis since, over the long term, decommissioning funding will be adequate.

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111 The Dow Jones Industrial Average closing price for March 31, 2009, was 7608.39; the close on July 31, 2009, was 9171.61.

112 The $1.7 billion was the gross shortfall for the merchant plants in 2009.

113 Nuclear Power Plant License Renewal, Final Rule, 56 FR 64943, December 13, 1991.

114 NUREG-1350, Volume 21, 2009–2010 Information Digest, Appendix B, August 2009.

Response 18

The staff compared the commenter's confident prediction of well-timed market growth with a similarly confident prediction from Shakespeare's King Henry IV:

> Glendower: I can call spirits from the vasty deep.
>
> Hotspur: Why, so can I, or so can any man;
> But will they come when you do call for them?[115]

Substitute, "I can call capital gains from the misty future," for Glendower's boast and Hotspur's skeptical retort applies equally well to the claim that the stock market will produce cash on demand to pay for decommissioning.

The claim that a long-term investment will cover decommissioning expenses relies on the assumption that the market will rise. Of course, many studies support the general notion of a long-term average rise in stock market value.[116] However, saying the market will rise is like saying Denver is uphill from San Francisco—true on the average, but it ignores significant peaks, valleys, and flats along the way. And, unlike the trip to Denver, the path of the market is unpredictable. The commenter ignored both volatility and unpredictability in his assumption.

Equally important, the commenter is forced to implicitly assume that the market will grow at a rate higher than the 2-percent real rate of return allowed by the NRC regulations. That assumption is required to support the commenter's argument because, when a shortfall occurs, the earnings credit projected using the NRC's 2-percent rate does not provide adequate funding to pay for decommissioning, when combined with all other methods of assurance provided by the licensee. That is, a cash flow analysis would show that the licensee would run out of money. Table 1, "Example Cash Flow Analysis," illustrates that situation. If the licensee does not provide any additional financial assurance to cover the shortfall, the argument that the investment will grow to fulfill the obligation amounts to a claim that the earnings credit will "really" be greater than a 2-percent real rate of return.[117] That implicit assumption exceeds the regulatory limit. The NRC considered and rejected using a higher real rate of return in its analysis for the 1998 Decommissioning Rule.[118]

However, many organizations have considered how much to rely on uncertain market returns as a source of funding for large future obligations. The staff reviewed this information to gain insight on how much weight should be given to potential market gains when determining how frequently adjustments should be made to cover shortfalls in decommissioning financial assurance.

As a first step, the staff examined actual market performance since the end of the 19th century. Table 4 displays data on long-term bear markets. The data reveal significant periods of time

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115 William Shakespeare, King Henry VI, Part I, Act 3, Scene 1. *Available at* http://www.shakespeare-literature.com/Henry_IV,_part_1/8.html

116 Peter A. Diamond, "What Stock Market Returns to Expect for the Future?," *Social Security Bulletin*, Vol. 63, No. 2, p. 38, 2000.

117 Public utility licensees may use a higher rate, if authorized by their rate regulator. The same arguments apply, but turn on the utility licensee's higher rate of return.

118 1998 Decommissioning Rule, 63 FR 50477

when the market did not rise at a rate greater than the NRC's 2-percent real rate of return allowance. When looking at the table, the annual returns cannot be directly compared to the NRC's 2-percent annual real rate of return. To make the comparison, the NRC's rate must be converted to a nominal rate that includes inflation. For example, during the period shown in the last row of Table 4, from 2/1/00 to 12/1/09, the inflation rate was approximately 2.7 percent per year.[119] When the inflation rate is added to the NRC's real rate, the result is approximately 4.7 per year. That is, applying the NRC's real rate of return to the period from 2/1/00 to 12/1/09 implies that the actual annual return would have been 4.7 percent. Using the inflation-adjusted annual rate, the market should have achieved a cumulative increase of about 58 percent, rather than the -4.68 percent it actually achieved. Inspection of Table 4 shows that actual performance fell short of the projection for the decade. The frequency and duration of the long-term bear markets appear significant enough to question the ability of capital gains to provide cash when needed. The staff concluded that a licensee that relied too heavily on projected earnings as a source of funds may encounter difficulty in accumulating adequate funds for decommissioning.

Table 4. Long-Term Bear Markets 1896 to 2009[120]
Dow Jones Industrial Average Index

Start Date	End Date	Duration in Years	Annual Return	Cumulative Return
2/1/06	6/1/24	18	-0.24%	-4.29%
9/1/29	11/1/54	25	0.07%	1.69%
2/1/66	10/1/82	17	0.05%	0.83%
2/1/00	12/1/09	10	-0.48%	-4.68%

The staff considered information gathered by the Social Security Advisory Board (SSAB). In 2001, the SSAB solicited the views of distinguished economists to consider whether to change the Social Security system to include some form of investment of funds in private equities.[121] A key element in the evaluation was whether historical rates of return for the last century should be used to make long-term projections over the coming decades or whether an alternative rate or range of rates is more appropriate.[122] Among the views presented to the SSAB were the following statements by Professor John Y. Campbell, who is the Morton L. and Carole S. Olshan Professor of Economics at Harvard University:

> The unprecedented nature of recent stock market behavior makes it impossible to base forecasts on historical patterns alone....[123]

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119 Inflation calculated from the Consumer Price Index – Urban, as compiled by the Bureau of Labor Statistics.

120 Rydex Security Global Investors, using data on the Dow Jones Industrial Average Index. For purposes of the chart, a secular bear market, or downward-trending market, occurs when a trend does not rise above the previous high. Available at http://www.getalts.com/downloads/dowJonesChart.shtml. Last visited May 27, 2010.

121 Forecasting U.S. Equity Returns in the 21st Century, Estimating the Real Rate of Return on Stocks Over the Long Term, Presented to the Social Security Advisory Board, p. 1, August 2001.

122 Id.

123 John Y. Campbell, "Forecasting U.S. Equity Returns in the 21st Century," Estimating the Real Rate of Return on Stocks Over the Long Term, Presented to the Social Security Advisory Board, p. 7, August 2001. Available at http://www.ssab.gov/Publications/Financing. Last visited April 6, 2010.

[I]t is impossible to predict timing of market corrections …[124]

Finally, I note that it is tricky to use these numbers appropriately in policy evaluation. … Even if the probability of underperformance is small over a long holding period, it cannot be zero or the stock market would be offering an arbitrage opportunity or "free lunch."[125]

Professor Eric D. Chason, Associate Professor of Law at the University of Virginia School of Law, provided a pithier statement of the uncertainty of market growth. The following statement appears in his article on pension funding shortfalls:

Volatility is a property of markets; it is not a disease for which accounting is the cure.[126]

Professor Chason's view particularly applies to the use of SAFSTOR to extend the time period for adding earnings credits to the amount of financial assurance. SAFSTOR does not cure market volatility.

A second set of pragmatic experts on decommissioning funding—namely, NRC licensees—support Professor Campbell's views that market growth cannot simply be assumed to cover future obligations. For example, Dominion Resources, Inc. (Dominion), owns seven operating reactors and one reactor in decommissioning. The following statement in Dominion's 2009 annual report to the SEC leaves no doubt that decommissioning trust funds may suffer poor market growth, which could require significant additional funding for decommissioning:

Market performance and other changes may decrease the value of decommissioning trust funds and benefit plan assets or increase Dominion's liabilities, which could then require significant additional funding.…These assets are subject to market fluctuation and will yield uncertain returns, which may fall below expected return rates.…If the decommissioning trust funds and benefit plan assets are not successfully managed, Dominion's results of operations and financial condition could be negatively affected.[127]

The Zion Nuclear Power Station (Zion) license transfer provides a case study illustrating that a well-informed industry participant will not rely on market growth as the basis for funding an actual decommissioning project.

In the Zion case, Exelon Generation Company, LLC (Exelon) agreed to transfer the license and decommissioning liability for the Zion site to ZionSolutions, LLC (ZionSolutions). ZionSolutions was formed for the sole purpose of decommissioning the Zion site and maintaining the Zion independent spent fuel storage facility; it is a wholly owned subsidiary of EnergySolutions,

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124 Id., p. 12.

125 Id., p. 8.

126 Eric D. Chason, "Outlawing Pension-Funding Shortfalls," *Va. Tax Rev*., Vol. 26, 2007, quoting Lawrence N. Bader & Jeremy Gold, "Reinventing Pension Actuarial Science," The Pension Forum, January 2003, at 1, 12.

127 Dominion Resources, Inc., Annual Report Pursuant to Section 13 of 15(d) of the Securities Exchange Act of 1934, Form 10-K, p. 24, February 26, 2010. Available at http://investors.dom.com.

Inc.[128] In exchange, ZionSolutions obtained the decommissioning trust funds. As originally agreed, the closing date for the transfer was scheduled for the end of 2008.[129] The project was expected to take 10 years.

However, after the transfer application was submitted, the Zion decommissioning trust fund balance declined about 10 percent by October 2008.[130] The drop in market value prompted EnergySolutions to defer the license transfer and delay the decommissioning start date as stated in the following announcement:

> EnergySolutions does not believe that it is in the best interests of its stakeholders to finalize the transfer of the Zion Nuclear Power Station assets until after the financial market stabilizes and the company reaffirms that there is sufficient value in the Zion decommissioning trust funds to ensure adequate funds for the accelerated decommissioning of the plant…[131]

EnergySolutions' decision to defer the Zion license transfer demonstrates that a well-informed market participant will not depend on market growth to cover a shortfall in funds needed to complete decommissioning.

The staff drew the following conclusions from the above information: (1) allowing shortfalls to persist implicitly accepts an earnings projection in excess of the amount provided in the NRC's regulations, (2) the probability of market underperformance over a long holding period is not zero, (3) using the 60-year SAFSTOR period to project earnings does not cure market volatility, (4) the consequences of market underperformance could require the licensee to provide significant additional funding, (5) a licensee that relied too heavily on market returns as a source of funds may encounter difficulty in accumulating adequate funds for decommissioning, and (6) market volatility can delay decommissioning. On that basis, the staff concluded that relying on unpredictable long-term market growth to cover a shortfall does not provide adequate financial assurance that funds will be available when needed.

However, additional reasons argue against reliance on long-term market growth to cover shortfalls.

Waiting for the markets to "sort themselves out"[132] gives a competitive advantage to licensees who choose to rely heavily on market gains to provide funds for decommissioning. They can increase net income a bit above similarly situated competitors that take a less optimistic view of the market as a funding method. The competitive advantage may provide an incentive for

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128 Application for License Transfers and Conforming Administrative License Amendments (hereinafter referred to as the Zion Transfer Application), cover letter, p. 2, January 25, 2008. (ADAMS Accession No. ML080310521)

129 Zion Transfer Application, Enclosure 6, Schedule & Financial Information for Decommissioning, p. 1, January 25, 2008.

130 Steve Daniels, "Credit Crisis Delays Start of Cleanup at Exelon's Zion Nuke," Crain's Chicago Business, October 14, 2008. Available at http://www.chicagobusiness.com/cgi-bin/news.pl?id=31397.

131 Id.

132 Exelon Generation Company, LLC stated that, "the most prudent course of action is to allow time for the financial markets to sort themselves out from such a fall in value…." Transcript, U.S. Nuclear Regulatory Commission Briefing On Decommissioning Funding, pp. 9–10, February 23, 2010. (ADAMS Accession No. ML010610257)

licensees to adopt a reactive strategy of addressing shortfalls after they occur, with no particular urgency, rather than following a forward-looking strategy of avoiding shortfalls.

Fairness issues arise when some smaller licensees do not have the same flexibility as the large fleet owners. An owner of a minority interest in a power reactor raised a fairness issue to a staff member attending the Nuclear Decommissioning Trust Fund Study Group in May 2010. The owner remarked that it must pay over the decommissioning charges required by its rate regulator annually. That owner expressed the view that it was unfair that small State-regulated utilities must pay when owners of large fleets of reactors are allowed to delay.[133]

The issue of fairness to future generations also comes into play when considering the market gain argument as a financial assurance method. In a 1977 report to Congress on the NRC's approach to decommissioning, the Comptroller General of the United States stated the following:

> We believe the cost of decommissioning should be paid by the current beneficiaries, not by future generations.[134]

Using future market gains to pay for decommissioning transfers the cost from the current beneficiaries of energy production to a future generation. The issue of intergenerational equity argues against heavy reliance on capital gains to fund decommissioning.

Finally, as a technical point, reliance on market gains would be difficult to use as a regulatory mechanism. Hope springs eternal that the market will rise quickly in the near future. Waiting for the markets to "sort themselves out" does not appear to have an obvious endpoint to select as a regulatory deadline.

Comment 19 SAFTOR Extends the Investment Horizon

As a collateral benefit, the long investment horizon provided by SAFSTOR increases the amount of financial assurance credited to a trust fund balance.

Response 19

The NRC's regulations provide 60 years or more, if approved, to decommission a reactor.[135] The decommissioning period may include a period of safe storage, known as SAFSTOR.[136] However, safety and waste disposal issues formed the NRC's basis for providing SAFSTOR as a decommissioning option:

- The primary purpose of the SAFSTOR period is to enhance worker safety by allowing time for decay of radioactivity in the workplace.[137]

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133 Personal communication, A. Simmons, NRC, reporting a comment made at the recent Nuclear Decommissioning Trust Fund Study Group meeting.

134 Cleaning Up the Remains of Nuclear Facilities—A Multibillion Dollar Problem, Report No. EMD-77-46, p. 25, June 16, 1977.

135 10 CFR 50.82(a)(3).

136 1988 Decommissioning Rule, 53 FR 24018, 24022.

137 Decommissioning Criteria for Nuclear Facilities, Proposed Rule, 50 FR 5600, 5603, February 11, 1985.

- Other factors that could delay decommissioning include the following:[138]
  - the unavailability of waste disposal capacity
  - the presence of operating nuclear facilities on the same site

In view of the purpose of SAFSTOR, the collateral effect of extending the period of projected earnings should not be understood to allow delay in covering a shortfall. The NRC's rules still require the licensee to accumulate the full amount of funds needed for decommissioning by the time of permanent shutdown. The Commission stated this requirement on at least four occasions as follows:

> Combination of these steps, first establishing a general level of adequate financial responsibility for decommissioning early in life, followed by periodic adjustment, and then evaluation of specific provisions close to the time of decommissioning, will provide reasonable assurance that the Commission's objective is met, namely that at the time of permanent end of operations sufficient funds are available to decommission the facility in a manner which protects public health and safety.[139] (1988)
>
> Moreover, the provisions of §§ 50.82(a) and 50.75(e) reflect the Commission's objective that *"at the time of permanent end of operations* sufficient funds are available to decommission the facility in a manner which protects public health and safety".[140] (1991) [emphasis in original]
>
> The NRC disagrees with recommendations that the NRC should abandon its general policy of requiring all funds needed for decommissioning be available prior to the start of final dismantlement. As described in the proposed rule (56 FR 41493), the June 27, 1988, final rule clearly requires funds at the time of permanent end of operations.[141] (1992)
>
> First, it should be noted that § 50.75(e)(1) and (2) also require full funding of decommissioning ''at the time termination of operation is expected.'' Thus, the commenters have not provided a complete picture of the situation.[142] (2002)

The NRC's rules allow a licensee to use earnings projected into the SAFSTOR period as part of its financial assurance. However, if a shortfall continues to exist after the SAFSTOR earnings credit is included, the licensee has exhausted the benefit and must cover the remaining shortfall. An example of a shortfall that exceeds the benefit of the additional earnings credit is discussed in Comment 20, "NRC Should Use NPV Methods for Financial Assurance Calculations."

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138 10 CFR 50.82(a)(3); 1988 Decommissioning Rule, 53 FR 24018, 24023.

139 1988 Decommissioning Rule, 53 FR 24018, 24030–31.

140 Decommissioning Funding for Prematurely Shutdown Power Reactors, Proposed Rule, 56 FR 41493, August 21, 1991.

141 Decommissioning Funding for Prematurely Shutdown Power Reactors, Final Rule, 57 FR 30384, 30395, July 9, 1992.

142 67 FR 78332, Decommissioning Trust Provisions, Final Rule, December 24, 2002.

NET PRESENT VALUE (NPV)

Comment 20 NRC Should Use NPV Methods for Financial Assurance Calculations

Using calculation methods that are not based on net present value improperly mix current and future values for the same obligation.

Response 20

The staff considers its use of current and future values appropriate for the purpose of evaluating compliance with the rule to provide financial assurance in an amount that may not be less than the specification of 10 CFR 50.75(c)(1) and 10 CFR 50.75(c)(2).

The staff is aware of the applications of NPV and discount rates for making decisions in capital investment analysis[143]. However, use of NPV can result in levels of financial assurance that are not adequate to pay for decommissioning.[144] An example of the NPV method that led to underestimating a shortfall in financial assurance is discussed below. But first, the NRC's method of incorporating inflation and future cash flows in its analysis will be discussed.

The first step in the NRC's evaluation makes an inflation adjustment to obtain the cost of decommissioning in current year dollars. The minimum estimated cost of decommissioning is specified in 1986 dollars in 10 CFR 50.75(c)(1). The escalation rate used to adjust the 1986 cost to current dollars is specified in 10 CFR 50.75(c)(2). The licensee must report the amount of funds accumulated for decommissioning in current year dollars in accordance with 10 CFR 50.75(f)(3). The escalation performed by the staff permits a direct comparison of the requirement to the licensee's reported funds.

If the licensee does not have sufficient funds in its decommissioning trust to cover the cost of decommissioning, the staff will include amounts assured by other methods, such as guarantees, projected earnings, and future payments. The staff uses 2009 dollars in this part of its analysis. That is, the amounts are not adjusted for inflation after 2009. The staff uses 2009 dollars to estimate the amounts expected to be received in the future for two reasons. First, it allows direct use of the 2-percent real rate of return specified in the regulations. The real rate of return is already adjusted to subtract inflation, as explained by the Federal Reserve Bank:

> Real interest:
> Interest rates adjusted for the expected erosion of purchasing power resulting from inflation. Technically defined as nominal interest rates minus the expected rate of inflation.[145]

Second, using constant 2009 dollars simplifies the evaluation. If nominal, inflation-adjusted future payments and earnings were included, the staff would need to make projections of the inflation rate. Then, it would convert the nominal future values back to 2009 dollars to complete the analysis. Using 2009 dollars throughout the analysis reduces the administrative burden on

143 1998 Decommissioning Rule, 63 FR 50465, 50477.
144 Id.
145 Glossary, The Federal Reserve Bank of Minneapolis. Available at http://www.minneapolisfed.org/glossary.cfm#r.

the staff. As noted in the 1988 Decommissioning Rule, one of the objectives of codifying financial assurance requirements was to reduce the administrative burden of providing financial assurance.[146] The constant dollar approach aligns with that objective.

As a result of using constant 2009 dollars for the analysis, a cash flow occurring in the future does not require discounting to be compared with a cash flow occurring in the present. Using the NPV method to discount the results of the NRC's evaluation could result in an inadequate amount of financial assurance, since it would amount to a double subtraction of inflation.

Table 5 below illustrates the differences between using the 2-percent earnings method and the NPV method to evaluate financial assurance. It compares the results of the staff analysis and the licensee analysis of financial assurance submitted for a power reactor with a shortfall as of December 31, 2009. The staff used the constant dollar method described above. The licensee used an NPV method. Both analyses express the cash flows in constant 2009 dollars and begin the analysis with the licensee's decommissioning trust fund balance as of December 31, 2009. The only point of agreement between the two methods is the fund balance as of October 17, 2026, when the plant operating license will expire.[147]

Enclosure 4 shows the decommissioning expense amounts and timing as determined by the licensee in a site-specific cost estimate. The first three years show high expense when the plant will be prepared for a 49 year safe storage period. Then, in 2079, the licensee plans to complete the decommissioning over a 10 year period. The staff found the expenses reasonable and used them for its cash flow analysis.

The staff analysis follows the method explained in the previous section titled, "NRC's Evaluation Method for Decommissioning Financial Assurance." The results are shown in Enclosure 3. The staff analysis shows the trust fund balances at the beginning and end of each year, with subtractions for the annual expense and additions for annual earnings at a 2-percent real rate of return. The staff analysis shows that the money will run out in 2083. There will be approximately $68 million in expenses remaining after the assured funds run out. The entries in Table 5 for the staff results can be read directly off the staff's spreadsheet.

The licensee's analysis is shown in Enclosure 4. It does not display the decommissioning trust fund balances or the earnings credit. The total expense can be read directly from the spreadsheet. However, the column labeled "Decommissioning Cost Less Decommissioning Period Credit" requires explanation. The licensee explained that the column represented the NPV of the decommissioning cost for the year, discounted back to 2026. As a result, the licensee's spreadsheet does not show that the money will run out in 2083. The licensee nevertheless determined that a shortfall existed, as shown in the boxed table on page 2 of Enclosure 4. The relevant figures are reproduced in Table 5.

Referring now to Table 5, an explanation is needed for the differences in the staff and licensee results. Turning first to the "Decommissioning Period Credit," the staff's figure is much less than the licensee's figure. The staff figure was calculated as the total of all the annual earnings on the trust fund balance from 2026 until the funds ran out, as shown on the staff spreadsheet.

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146 1988 Decommissioning Rule, 53 FR 24030.

147 The slight difference in projections appears to be due to details of how spreadsheets handle the number of days in a leap year.

The licensee calculated the figure by subtracting the total of its annual "Decommissioning Cost Less Decommissioning Credit" values from the total decommissioning cost. Or, more concisely, the licensee subtracted the NPV of the expenses from the expenses. The staff was unable to discover a logical reason why the licensee's calculation would yield a result that equaled the 2-percent earnings calculation performed by the staff. In any event, comparing the licensee figure to the staff figure shows that the licensee figure for the credit exceeds the amount of cash that the trust fund balance is projected to earn using the 2-percent rate, after subtracting the decommissioning expense. The staff concluded that the licensee's calculation of the amount of earnings credited to the decommissioning trust was incorrect.

Table 5 shows that the staff and the licensee estimated different shortfall amounts. Note, however, that the shortfall amounts depend on the date. The staff used 2009 dollars since that is the date at which the shortfall must be covered. The licensee selected two dates to calculate the NPV of the shortfall – 2026 and 2009. Referring to the boxed table on page 2 of Enclosure 4, the licensee calculated the shortfall as $14 million and $10 million. The $14 million figure represents the difference between the licensee's estimated actual and required amount of financial assurance as of the date of license expiration. The $10 million figure represents the licensee's estimate of how much additional cash would be needed in the decommissioning trust as of 2009 to increase the projected earnings enough to cover the projected expenses. The staff concluded the licensee's calculations were incorrect.

The last row of Table 5 shows the projected trust fund amount calculated by the staff and the licensee. The staff's figure of $286 million can be read off its spreadsheet. The highest value occurs on the first day, since the expenses draw down the balance faster than the earnings can replenish it. The licensee's calculation appears on the page 2 of Enclosure 4. The licensee calculated the total projected trust fund amount by adding the balance on October 17, 2026 to its figure for "Decommissioning Period Credit" to arrive at $600 million. The staff concluded that the licensee's calculation was incorrect.

The example shows that the NPV method can produce an incorrect and undervalued result for a shortfall in decommissioning financial assurance.

Table 5. Comparison of Staff and Licensee Calculations of Shortfall ($ 2009)

Calculated Amount	Staff Calculation Using 2% Return	Licensee Calculation Using NPV Method
10/17/2026 Balance	286,249,000	286,233,000
Plus Decommissioning Period Credit	259,519,864	313,775,000
Less Total Cost	614,184,000	614,184,000
Surplus (Shortfall) as of 2026	Not calculated	(14,179,000)
Surplus (Shortfall) as of 2009	(68,415,136)	(10,166,000)
Total Projected Trust Fund Amount	286,249,000	600,008,000

An additional weakness of the NPV concept bears mentioning. NPV varies depending on the future time at which the shortfall occurs, so equal shortfalls may yield different NPVs, which

make comparison of licensee performance more complex. Table 6 below illustrates this weakness. The time periods were selected to show the difference for a renewed license term, a full-term license, and a renewed license term plus a 53-year safe storage period following permanent shutdown.

Table 6. Variability in NPV of Shortfall

Shortfall	NPV @ 2% for Shortfall Occurring in the Future		
	20 Years in Future	40 Years in Future	73 Years in Future
$100,000,000	$67,297,133	$45,289,042	$23,560,661

The above discussion explains why the NRC does not use NPV to determine the amount of a shortfall.

Comment 21 NRC Does Not Comply with Generally Accepted Accounting Procedures

Using calculation methods that are not based on net present value is at odds with generally accepted accounting practices (GAAP).

Response 21

The staff disagreed that GAAP restrict the NRC's authority to choose the method best suited to make its independent evaluation of the adequacy of financial assurance provided by a licensee. The Commission addressed that point in its 1998 Decommissioning Rule as follows:

> The commenter's concern that 2 percent is less than the 7 percent and 3 percent discount rates called for in NRC's regulatory analysis guidance is not relevant. Discount rates are used for capital investment analysis and other decision-making purposes but, if used to calculate contributions to decommissioning funds, could result in financial assurance levels that are not adequate to pay for all assured obligations.[148]

The staff referred to the FASB for additional insight on the applicability of GAAP to the NRC's evaluation of licensee financial assurance. Since 1973, FASB has been designated by the SEC as the private-sector standard setter for GAAP for the United States.[149] Based on statements issued by the FSAB, the NRC sees no contradiction in using methods other than GAAP to make its decisions. In the following statement, FASB recognizes that GAAP are limited in the role they play:

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148 63 FR 50465, 50477.

149 William W. Bratton, "Private Standards, Public Governance: A New Look At The Financial Accounting Standards Board," p. 7, *Boston College L. Rev.*, Vol. 48:1, January 2007.

> The role of financial reporting in the economy is to provide information that is useful in making business and economic decisions, not to determine what those decisions should be.[150]

Furthermore, FASB recognizes that end users of financial reports have a responsibility to do their own independent evaluation of information reported under GAAP, as stated below:

> Investors, creditors, and others may use reported earnings and information about the elements of financial statements in various ways to assess the prospects for cash flows. They may wish, for example, to evaluate management's performance, estimate "earning power," predict future earnings, assess risk, or to confirm, change, or reject earlier predictions or assessments. Although financial reporting should provide basic information to aid them, they do their own evaluating, estimating, predicting, assessing, confirming, changing, or rejecting.[151]

The independent evaluation performed by the NRC is consistent with that responsibility.

Comment 22 Licensees Should Be Permitted to Use NPV Methods

Licensees should be permitted to use net present value methods to determine the amount of a guarantee provided for financial assurance.

Response 22

The staff disagreed for three reasons.

First, as demonstrated in the response to Comment 20, "NRC Should Use NPV Methods for Financial Assurance Calculations," the NPV method can result in financial assurance levels that are not adequate to meet all future obligations.

Second, the regulations provide for an earnings credit only for funds held in a prepaid account or an external sinking fund. The regulations governing the guarantee methods do not provide for an earnings credit.

Third, there are no funds associated with a PCG or other guarantee method, so there is nothing that can generate earnings.

Some licensees have suggested that the PCG could be converted into cash, which could be placed in an account that produces earnings. Therefore, an earnings credit should be added to the face amount of the PCG for financial assurance purposes. To see why the potential convertibility does not solve the problem, think of a PCG as a box of money buried in the ground that will be dug up to pay for a shortfall in financial assurance. No matter how long you wait, it is just a box of money with exactly the same amount as when it was buried. For example, suppose that the licensee will have a shortfall of $30 million dollars 20 years in the future. The

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150 Statement of Financial Accounting Concepts No. 1, Objectives of Financial Reporting by Business Enterprises, as amended, FASB, p. 10, November 1978. Available at http://www.fasb.org.

151 Id., p. 2.

NPV of that shortfall, using a 2-percent discount rate, is $20 million. The licensee puts $20 million in a box and buries it on site. Twenty years later, when the licensee digs up the box, it still has $20 million. The box full of money is not enough to pay the $30 million shortfall.

Comment 23 NRC Approved NPV Methods in the Past

The NRC approved three license transfers which included parent company guarantees calculated by the applicant using the net present value method.

Response 23

With respect to the license transfer cases referenced by the commenter, the staff noted that each case was completed before the staff issued its procedure for analyzing reactor decommissioning funding assurance. The procedure is Office Instruction LIC-205, "Procedures for NRC's Independent Analysis of Decommissioning Funding Assurance for Operating Nuclear Power Reactors." LIC-205 was issued in 2006, while the latest of the references provided by the commenter was completed in 2005. Consequently, the three cases have no value as precedent. LIC-205 established the method used by the NRC to measure the adequacy of the licensee's financial assurance and determine the amount of a shortfall, if any. Due to the lack of regulatory provisions to apply NPV calculations to the guarantee methods, as well as the inherent inaccuracy of the method when used to determine the adequacy of financial assurance, LIC-205 does not provide for the NPV method.

UTILITY LICENSEES

Comment 24 Do Not Address Funding in Every Rate Case

The guidance should not state that public utility licensees should address decommissioning funding at every rate case.

Response 24

The staff agreed that addressing decommissioning funding in "every" rate case before the licensee's rate regulator could lead to duplication of effort. A licensee may have more than one active docket before its rate regulatory authority. The final version of RG 1.159, Revision 2, will not advise the licensee to address decommissioning funding at every rate case.

Comment 25 Good Faith Efforts for Rate Relief

Guidance endorsing good-faith efforts by public utility licensees to obtain rate relief should not be removed from the existing guidance. A reasonable amount of time should be allowed to pursue rate relief.

Response 25

The statement on good-faith efforts was removed from the proposed guidance in favor of stating that the licensee should address decommissioning funding in every rate case. As noted above, the final version of RG 1.159, Revision 2, will not recommend that the licensee address decommissioning funding in every rate case.

When the commenter proposed reinstating guidance that the licensee should use good-faith efforts to obtain rate relief, no suggestion was made on what action would constitute a good-faith effort. The commenter offered no suggestion on the timeframe to complete the action.

Two objectives informed the staff's evaluation of what action would constitute a good-faith effort by the licensee and the time period for taking the action.

First, the NRC has a policy to minimize its involvement with the rate-making process.[152] Obtaining rate relief for a shortfall would logically start with the rate regulator receiving information that the shortfall had occurred. The rate regulators perform periodic reviews of decommissioning costs and funding. However, State rate regulators perform reviews of decommissioning fund balances on a frequency that generally ranges from semiannual to once every 5 years.[153] One option for a licensee would be to wait until the next scheduled rate review to inform its rate regulator of the shortfall. However, that strategy may not be appropriate, depending on the size of the shortfall, the time when the next review is scheduled, and the time when the decommissioning funds will be needed. Another consideration is that waiting for the next scheduled review does not constitute taking action.

The staff concluded that the licensee should take self-initiated action to notify its rate regulator when a shortfall occurs and request a review of decommissioning funding. The rate regulator can then use its processes to determine the appropriate timing and level of adjustment in ratepayer collections. In addition, action by the licensee will minimize the involvement of the NRC in the process, as compared to the NRC communicating directly with the rate regulator to provide information on a licensee's shortfall.

Second, in considering the timing of the licensee's action, the staff was informed by the NRC's policy that requires the licensee to provide adequate financial assurance at all times. This policy states the following:

> A licensee is required to provide assurance that at any time during the life of the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning.[154]

As discussed in Introduction, the optimal timing to cover a shortfall is annually. That conclusion was based on the CY experience of economic distress within 3 years, the apparent decline in effectiveness of the existing 2-year guidance, and the requirement that the licensee must provided adequate financial assurance at any time during the life of the facility. The timing for a utility licensee to notify its rate regulator should be March 31, when a shortfall occurs on the previous December 31. The March and December dates coincide with the reporting requirements of 10 CFR 50.75(f) and are consistent with the guidance for merchant plant licensees. In the notification, the licensee should describe the amount of the shortfall and the potential effect it could have on decommissioning funding. The licensee should request that its rate regulator review its decommissioning funding within the year.

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152 1988 Decommissioning Rule, 53 FR 24030.

153 SECY-07-0197 (ML072610606)

154 Decommissioning of Nuclear Power Reactors, Final Rule, 61 FR 39278, July 29, 1996.

The staff determined that the 6 year period to obtain rate relief in the existing guidance should be reduced to 5 years to coincide with upper end of the typical rate regulator review schedule.

Putting the burden of notification on the licensee conforms to the NRC's policy of minimizing its involvement with the rate regulatory process. However, the NRC retains the authority to take additional actions, either independently or in cooperation with FERC or the licensee's State public utilities commission, as appropriate, including modification of the schedule to accumulate funds.

EDITORIAL COMMENT

Comment 26 References in Guidance

References cited in the guidance should be updated.

Response 26

The staff agreed.

Staff Calculation Using 2% Earnings

SAFSTOR Cash Flow ($ 2009)

12/31/2009 Fund Balance = 205,217,000

License expiration 10/17/2026

Beginning Fund Balance - Expense + 2% Earnings = Ending Fund Balance

Year [1]	Beginning Fund Balance	Expense [2] 12/31/2009 dollars	2% Earnings	Ending Fund Balance
10/17/2026 [3]	286,249,000	9,819,000	1,136,014	277,566,014
2027	277,566,014	53,297,000	4,485,380	228,754,394
2028	228,754,394	12,862,000	4,317,848	220,210,242
2029	220,210,242	3,739,000	4,329,425	220,800,667
2030	220,800,667	3,739,000	4,341,233	221,402,900
2031	221,402,900	3,739,000	4,353,278	222,017,178
2032	222,017,178	3,746,000	4,365,424	222,636,602
2033	222,636,602	3,734,000	4,378,052	223,280,654
2034	223,280,654	3,734,000	4,390,933	223,937,587
2035	223,937,587	3,734,000	4,404,072	224,607,658
2036	224,607,658	3,745,000	4,417,253	225,279,912
2037	225,279,912	3,734,000	4,430,918	225,976,830
2038	225,976,830	3,734,000	4,444,857	226,687,686
2039	226,687,686	3,734,000	4,459,074	227,412,760
2040	227,412,760	3,745,000	4,473,355	228,141,115
2041	228,141,115	3,734,000	4,488,142	228,895,258
2042	228,895,258	3,734,000	4,503,225	229,664,483
2043	229,664,483	3,734,000	4,518,610	230,449,092
2044	230,449,092	3,745,000	4,534,082	231,238,174
2045	231,238,174	3,734,000	4,550,083	232,054,258
2046	232,054,258	3,710,000	4,566,885	232,911,143
2047	232,911,143	3,710,000	4,584,023	233,785,166
2048	233,785,166	3,720,000	4,601,303	234,666,469
2049	234,666,469	3,710,000	4,619,129	235,575,599
2050	235,575,599	3,710,000	4,637,312	236,502,910
2051	236,502,910	3,710,000	4,655,858	237,448,769
2052	237,448,769	3,720,000	4,674,575	238,403,344
2053	238,403,344	3,710,000	4,693,867	239,387,211
2054	239,387,211	3,710,000	4,713,544	240,390,755
2055	240,390,755	3,710,000	4,733,615	241,414,370
2056	241,414,370	3,720,000	4,753,887	242,448,258
2057	242,448,258	3,710,000	4,774,765	243,513,023
2058	243,513,023	3,710,000	4,796,060	244,599,083
2059	244,599,083	3,710,000	4,817,782	245,706,865
2060	245,706,865	3,720,000	4,839,737	246,826,602
2061	246,826,602	3,710,000	4,862,332	247,978,934
2062	247,978,934	3,710,000	4,885,379	249,154,313
2063	249,154,313	3,710,000	4,908,886	250,353,199
2064	250,353,199	3,720,000	4,932,664	251,565,863

Staff Calculation Using 2% Earnings

SAFSTOR Cash Flow ($ 2009)

12/31/2009 Fund Balance = 205,217,000

License expiration 10/17/2026

Beginning Fund Balance - Expense + 2% Earnings = Ending Fund Balance

Year [1]	Beginning Fund Balance	Expense [2] 12/31/2009 dollars	2% Earnings	Ending Fund Balance
2065	251,565,863	3,710,000	4,957,117	252,812,980
2066	252,812,980	3,710,000	4,982,060	254,085,040
2067	254,085,040	3,710,000	5,007,501	255,382,541
2068	255,382,541	3,720,000	5,033,251	256,695,792
2069	256,695,792	3,710,000	5,059,716	258,045,508
2070	258,045,508	3,710,000	5,086,710	259,422,218
2071	259,422,218	3,710,000	5,114,244	260,826,462
2072	260,826,462	3,720,000	5,142,129	262,248,591
2073	262,248,591	3,710,000	5,170,772	263,709,363
2074	263,709,363	3,710,000	5,199,987	265,199,350
2075	265,199,350	3,710,000	5,229,787	266,719,137
2076	266,719,137	3,720,000	5,259,983	268,259,120
2077	268,259,120	3,710,000	5,290,982	269,840,103
2078	269,840,103	3,710,000	5,322,602	271,452,705
2079	271,452,705	14,085,000	5,147,354	262,515,059
2080	262,515,059	52,128,000	4,207,741	214,594,800
2081	214,594,800	101,665,000	2,258,596	115,188,396
2082	115,188,396	81,365,000	676,468	34,499,864
2083	34,499,864	43,658,000	0	(9,158,136)
2084	0	34,244,000	0	(43,402,136)
2085	0	2,233,000	0	(45,635,136)
2086	0	22,580,000	0	(68,215,136)
2087	0	88,000	0	(68,303,136)
2088	0	88,000	0	(68,391,136)
2089	0	24,000	0	(68,415,136)
Total		614,184,000	259,519,864	

Notes:

[1] All years start on Jan. 1, except first year

[2] Expense data provided by licensee

[3] 75 days interest from date of shutdown

Staff Calculation of Surplus (Short)	
Projected 10/17/2026 Balance	286,249,000
Plus Decommissioning Period Earnings	259,519,864
Less Total Cost	614,184,000
Surplus (Short) as of 2009 =	(68,415,136)

Licensee Calculation Using NPV

SAFSTOR Cash Flow ($ 2009)

12/31/2009 Fund Balance = 205,217,000

10/17/2026 Projected Fund Balance = 286,233,000

License expiration 10/17/2026

Year	Decommissioning Cost 12/31/2009 dollars	Decommissioning Cost Less Decommissioning Period Credit [1]
2026	9,819,000	9,723,000
2027	53,297,000	51,737,000
2028	12,862,000	12,240,000
2029	3,739,000	3,489,000
2030	3,739,000	3,420,000
2031	3,739,000	3,353,000
2032	3,746,000	3,294,000
2033	3,734,000	3,219,000
2034	3,734,000	3,156,000
2035	3,734,000	3,094,000
2036	3,745,000	3,042,000
2037	3,734,000	2,974,000
2038	3,734,000	2,916,000
2039	3,734,000	2,858,000
2040	3,745,000	2,810,000
2041	3,734,000	2,747,000
2042	3,734,000	2,694,000
2043	3,734,000	2,641,000
2044	3,745,000	2,596,000
2045	3,734,000	2,538,000
2046	3,710,000	2,472,000
2047	3,710,000	2,424,000
2048	3,720,000	2,383,000
2049	3,710,000	2,330,000
2050	3,710,000	2,284,000
2051	3,710,000	2,239,000
2052	3,720,000	2,201,000
2053	3,710,000	2,152,000
2054	3,710,000	2,110,000
2055	3,710,000	2,069,000
2056	3,720,000	2,034,000
2057	3,710,000	1,988,000
2058	3,710,000	1,949,000
2059	3,710,000	1,911,000
2060	3,720,000	1,879,000
2061	3,710,000	1,837,000
2062	3,710,000	1,801,000
2063	3,710,000	1,765,000
2064	3,720,000	1,736,000

Licensee Calculation Using NPV
SAFSTOR Cash Flow ($ 2009)

12/31/2009 Fund Balance = 205,217,000
10/17/2026 Projected Fund Balance = 286,233,000

License expiration 10/17/2026

Year	Decommissioning Cost 12/31/2009 dollars	Decommissioning Cost Less Decommissioning Period Credit [1]
2065	3,710,000	1,697,000
2066	3,710,000	1,664,000
2067	3,710,000	1,631,000
2068	3,720,000	1,603,000
2069	3,710,000	1,568,000
2070	3,710,000	1,537,000
2071	3,710,000	1,507,000
2072	3,720,000	1,481,000
2073	3,710,000	1,448,000
2074	3,710,000	1,420,000
2075	3,710,000	1,392,000
2076	3,720,000	1,369,000
2077	3,710,000	1,338,000
2078	3,710,000	1,312,000
2079	14,085,000	4,883,000
2080	52,128,000	17,716,000
2081	101,665,000	33,873,000
2082	81,365,000	26,578,000
2083	43,658,000	13,982,000
2084	34,244,000	10,752,000
2085	2,233,000	687,000
2086	22,580,000	6,814,000
2087	88,000	26,000
2088	88,000	25,000
2089	24,000	7,000
Total	614,187,000	300,412,000

Decommissioning Period Credit = Decommissioning Cost - Decommissioning Cost Less Decommisioning Credit
313,775,000 = 614,187,000 - 300,412,000

Total Projected Trust Fund Amount = 10/17/2026 Balance + Decommisisoning Period Credit
600,008,000 = 286,233,000 + 313,775,000

Note:

[1] Values are the net present value (NPV) of annual Decommissioning Cost discounted to 2026

Licensee Calculation of Surplus (Short)	
Projected 10/17/2026 Balance	286,233,000
Plus Decommissioning Period Credit	313,775,000
Less Total Cost	614,187,000
Surplus (Short) as of 10/17/2026 =	(14,179,000)
Surplus (Short) as of 12/31/2009 =	(10,166,000)

Proposed Final Section 1.3 of REGULATORY GUIDE 1.159, Revision 2, “Assuring the Availability of Funds for Decommissioning Nuclear Reactors” (Draft was issued as DG-1229)

No change from DG-1229.

Change from RG 1.159, Revision 1 was to update references. See underlined paragraph. Revised sentence listing items outside the scope of the decommissioning process. See underlined text.

1.3 Decommissioning Cost Estimates

Five decommissioning cost estimates are required to be developed and submitted for NRC review:

(1) initial estimate that may be calculated according to 10 CFR 50.75(c), or that may be site-specific and at least equal to the decommissioning cost from 10 CFR 50.75(c);

(2) preliminary decommissioning cost estimate at or about 5 years before the projected end of operations, in accordance with 10 CFR 50.75(f)(2);

(3) estimate of expected costs contained in the PSDAR, in accordance with 10 CFR 50.82(a)(4)(i);

(4) site-specific decommissioning cost estimate within 2 years following permanent cessation of operations, in accordance with 10 CFR 50.82(a)(8)(iii);

(5) updated site-specific estimate of remaining decommissioning costs contained in the license termination plan, in accordance with 10 CFR 50.82(a)(9)(ii)(F).

The NRC developed guidance providing details on content and format for the reporting of these cost estimates and published it in Regulatory Guide 1.202, “Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors,” issued February 2005 (Ref. 8), and in NUREG-1713, “Standard Review Plan for Decommissioning Cost Estimates for Nuclear Power Reactors,” issued December 2004 (Ref. 9).

In general, decommissioning cost estimates are provided by major activity and major decommissioning phase or time period. The cost estimate must account for the entire decommissioning work scope but not for items that are outside the scope of the decommissioning process. Examples of activities outside of decommissioning include, but are not limited to: 1) the maintenance and storage of spent fuel, 2) the design and/or construction of a spent fuel dry storage facility, 3) activities that are not directly related to supporting long-term storage of the facility, or 4) any other activities not directly related to radiological decontamination of the site. If nondecommissioning cost items are included, these items should be identified separately.

Cost estimates should provide costs for each of the following (or similar) major activities and phases with a level of detail appropriate to the type of cost estimate:

(1) major radioactive component removal—reactor vessel and internals, steam generators, pressurizers, large-bore reactor coolant system piping, and other large components that are radioactive to a comparable degree;

(2) radiological D&D—removal of remaining radioactive plant systems, including radiological decontamination;

(3) management and support (undistributed costs)—costs such as labor costs of utility support staff and decommissioning contractor staff, energy costs, regulatory costs, small tools, insurance, etc.;

(4) waste packaging/shipping—placing waste in packages and shipping to waste vendors or burial site;

(5) waste burial or waste vendor—waste burial charges, including waste vendors' processing fees;

(6) contingency—allowance for unexpected costs.

Cost estimates should also include the assumptions, references, and bases for unit costs used in developing the estimates, as well as a description of how inflation is accounted for in the cost estimate. The cost estimate should be provided in current-year dollars. Escalation of the waste disposition costs is considered separately from the general inflation rate applicable to labor, material, and energy costs. Regulatory Position 1.2 discusses escalation factors.

Proposed Final Section 2.1.5 of REGULATORY GUIDE 1.159, Revision 2, “Assuring the Availability of Funds for Decommissioning Nuclear Reactors” (Draft was issued as DG-1229)

Change from DG-1229 was to add a reference to Commission policy requiring adequate financial assurance at all times during the life of the facility, to remove guidance that utility licensees should address decommissioning funding in every rate case, add guidance on good faith effort to obtain rate relief, and rewrite for clarity.

Change from RG 1.159, Revision 1: in addition to changes to DG-1229, increased frequency of covering shortfalls for merchant plant licensees from 2 years to 1 year, and for utility licensees from every 6 years to every 5 years.

2.1.5 A licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning. See 61 FR 39278. Pursuant to 10 CFR 50.75(b)(1) and (b)(2), the minimum amount of financial assurance required for decommissioning must be adjusted annually, using a rate at least equal to that stated in paragraph (c)(2) of 10 CFR 50.75. The licensee should calculate the amount of the adjustment as of December 31 of each year. If the amount of financial assurance provided by the licensee does not equal or exceed the minimum required amount of financial assurance recalculated on December 31, then the licensee must adjust the amount of financial assurance it provides, such that it meets or exceeds the required amount.

The adjustment in the amount being provided should occur by March 31 of each year, based on the amount of financial assurance as recalculated by the licensee on December 31 of the preceding year. The staff will normally evaluate the amount of financial assurance provided by the licensee in conjunction with the decommissioning funding status report required biennially, or annually in some cases, pursuant to 10 CFR 50.75(f).

However, under the provisions of 10 CFR 50.75(e)(2), the staff reserves the right to review, as needed, the rate of accumulation of decommissioning funds and, either independently or in cooperation with the FERC and the licensee’s State PUC, take additional actions on a case-by-case basis, including modification of the licensee’s schedule for the accumulation of funds.

A licensee that may rely exclusively on an external sinking fund to provide financial assurance under the circumstances defined in 10 CFR 50.75(e)(ii)(A) or (B), that is, where the total cost of decommissioning is provided through rates established by cost-of-service ratemaking or non-bypassable charges, may make a good-faith effort to obtain rate relief to cover its shortfall. A licensee meeting these criteria should inform its rate regulator by March 31 of each year when a shortfall in financial assurance has occurred as of December 31 of the preceding year. The information should include the NRC minimum financial assurance requirement, the actual amount of the licensee’s decommissioning financial assurance, and the amount of additional cost recovery needed to meet the NRC amount. The licensee should request its rate regulator to schedule a review of decommissioning cost recovery by the end of the year. A copy of the information and request should be included in the licensee’s decommissioning fund status report in the years that the report is required. The licensee is expected to obtain rate relief as necessary to meet the minimum requirement of 10 CFR 50.75(c), but in any case, within 5 years.

Proposed Final Section 2.2.8 of REGULATORY GUIDE 1.159, Revision 2, “Assuring the Availability of Funds for Decommissioning Nuclear Reactors” (Draft was issued as DG-1229)

No change from DG-1229.

Changes from RG 1.159, Revision 1:

- Section 2.2.8.1. Delete sentence, “A reasonable time may be used to make up any deficit, consistent with good-faith efforts to obtain rate relief.” See strikethrough text.
- Section 2.2.8.2. Add phrase, “that will provide the total amount of funds necessary for decommissioning.” See underlined text.
- Section 2.2.8.4. Add sentence, “The allowed credit during the period of safe storage must reflect any withdrawals from decommissioning funds during this period, such as withdrawals to pay for annual costs to maintain the facility in a safe storage condition.“ See underlined text.
- Add subsection numbers 2.2.8.1 through 2.2.8.7.

2.2.8 Annual deposits in an external sinking fund, including projected earnings, should attempt to approximate the total amount remaining to be accumulated, divided by the remaining years of the license, as determined by the initial and updated certification amount specified in 10 CFR 50.75(c)(1) and (2).

2.2.8.1 Arithmetic precision is not required for fund accumulation rates. If, during the course of collecting funds, a licensee has accumulated significantly greater decommissioning funds than anticipated, it may reduce its remaining contributions commensurately. Likewise, if a licensee is significantly behind in collections, increased contributions should be used to make up the deficit. ~~A reasonable time may be used to make up any deficit, consistent with good-faith efforts to obtain appropriate rate relief.~~ However, licensees should avoid undue reliance upon contributions weighted in constant dollars toward the end of projected facility operating life. Additionally, the NRC staff considers reliance on an estimated tax deduction for decommissioning expenses, at the time such expenses are incurred, to be a form of internal reserve and thus not allowed under 10 CFR 50.75(e). If sufficient rate relief by a State PUC or FERC is ultimately not obtained, the licensee’s stockholders will be expected to cover decommissioning costs through reduced return on equity. Projected rates of earnings on an external sinking fund during plant operation should reasonably approximate the historical real rate of earnings (i.e., after inflation and taxes) obtained by a given type of investment.

2.2.8.2 For decommissioning funds that are prepaid or in external sinking fund accounts, the regulations in 10 CFR 50.75(e)(i) and (ii) allow a credit for projected earnings of up to a 2 percent annual real rate of return (i.e., nominal rate less inflation and taxes) from the time of the future funds’ collection as a factor in calculating the total amount of funds that would be sufficient to pay decommissioning costs. This allowed credit may be greater than 2 percent if a licensee is subject to a rate-setting authority <u>that will provide the total amount of funds necessary for decommissioning</u> and the authority has specifically presumed a higher rate. The period of time for which the credit may be taken is determined by whether a generic formula or a site-specific estimate with a specified safe-storage period is used as the basis for estimating decommissioning costs, as discussed below.

2.2.8.3 For licensees that use a generic formula for decommissioning cost estimates, during the period of plant operation this credit may be taken for the remaining years left on the operating license, and an additional pro-rata credit may be taken into the presumed immediate dismantlement period (i.e., the first 7 years after shutdown), as long as such credit reflects the expected cash flow of

expenditures during this period. If license renewal for a plant has been approved by the NRC, the licensee may take the credit during the extended license period.

2.2.8.4 A licensee that uses a site-specific estimate may take the allowed credit through the projected decommissioning period, provided that the site-specific estimate is based on a period of safe storage that is specifically described in the estimate. This decommissioning period includes the period of safe storage, final dismantlement, and license termination. <u>The allowed credit during the period of safe storage must reflect any withdrawals from decommissioning funds during this period, such as withdrawals to pay for annual costs to maintain the facility in a safe storage condition.</u>

2.2.8.5 When a licensee adjusts the cost estimate for decommissioning annually, pursuant to 10 CFR 50.75(b)(2), the adjusted estimate less amounts already accumulated should form the basis of future collections, which can take into account the allowed credit. Funds already accumulated, plus scheduled fund contributions, in the case of those licensees authorized to utilize external sinking funds, plus projected earnings on these funds, should be sufficient to pay decommissioning costs at the time termination of operation is expected, allowing for extending the real rate of return credit into the decommissioning period, as noted above.

2.2.8.6 Actual earnings on existing funds may be used to calculate the need for future funds. However, pursuant to 10 CFR 50.75(f)(3), when a licensee is within 5 years of the projected end of operations and submits its preliminary decommissioning cost estimate, the licensee may take up to a 2 percent earnings credit (or a higher credit, if specifically presumed by a rate-setting authority) over a storage period, as long as the storage period and its cost implications for total decommissioning costs are specifically addressed in the preliminary decommissioning cost estimate.

2.2.8.7 Licensees who operate multiple modular reactors at a single site may take credit for earnings in such a manner that the assumptions for earnings credit track the cash flows for decommissioning expenses for each module.

Proposed additional definitions for RG 1.159

decommissioning financial assurance – The system of regulation used by the NRC to assure that funds are available when needed for decommissioning. It also refers to the total amount of assurance provided using one or more of the methods specified in 10 CFR 50.75(e). When referring to the total amount of financial assurance, it is the sum of funds accumulated in a segregated account outside the licensee's control; plus the amount of any guarantees provided; plus the projected amounts of earnings on the accumulated funds; plus projected ratepayer collections by utilities; plus projected non-bypassable charges authorized by a rate regulatory agency; plus, for government licensees, the amount provided by a statement of intent; plus projected payments from certain contractual obligations that meet NRC requirements; plus projected earnings on collections, payments, and non-bypassable charges. If applicable, financial assurance may include other methods if the NRC determines that they provide a level of assurance equivalent to the methods of 10 CFR 50.75(e). A licensee is required to provide financial assurance at all times during the life of the facility through termination of the license, that adequate funds will be available to complete decommissioning. (61 FR 39278)

shortfall – Where the amount of financial assurance provided by the licensee is less than the amount of financial assurance required, the difference is the shortfall.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

October 25, 2010

OFFICE OF THE SECRETARY

COMMISSION VOTING RECORD

DECISION ITEM: SECY-10-0084

TITLE: EXPLANATION OF CHANGES TO REVISION 2 TO REGULATORY GUIDE 1.159, "ASSURING THE AVAILABILITY OF FUNDS FOR DECOMMISSIONING NUCLEAR REACTORS"

The Commission (with Commissioners Svinicki, Apostolakis, Magwood, and Ostendorff approving in part and disapproving in part and Chairman Jaczko approving) acted on the subject paper as recorded in the Staff Requirements Memorandum (SRM) of October 25, 2010.

This Record contains a summary of voting on this matter together with the individual vote sheets, views and comments of the Commission.

Annette L. Vietti-Cook
Secretary of the Commission

Attachments:
1. Voting Summary
2. Commissioner Vote Sheets

cc: Chairman Jaczko
Commissioner Svinicki
Commissioner Apostolakis
Commissioner Magwood
Commissioner Ostendorff
OGC
EDO
PDR

VOTING SUMMARY - SECY-10-0084

RECORDED VOTES

	APRVD	DISAPRVD	ABSTAIN	NOT PARTICIP	COMMENTS	DATE
CHRM. JACZKO	X				X	9/28/10
COMR. SVINICKI	X	X			X	9/13/10
COMR. APOSTOLAKIS	X	X			X	10/13/10
COMR. MAGWOOD	X	X			X	10/8/10
COMR. OSTENDORFF	X	X			X	10/14/10

COMMENT RESOLUTION

In their vote sheets, Commissioners Svinicki, Apostolakis, Magwood, and Ostendorff approved in part and disapproved in part and Chairman Jaczko approved the staff's response and provided some additional comments. Subsequently, the comments of the Commission were incorporated into the guidance to staff as reflected in the SRM issued on October 25, 2010.

NOTATION VOTE

RESPONSE SHEET

TO: Annette Vietti-Cook, Secretary

FROM: Chairman Gregory B. Jaczko

SUBJECT: SECY-10-0084 – EXPLANATION OF CHANGES TO REVISION 2 TO REGULATORY GUIDE 1.159, "ASSURING THE AVAILABILITY OF FUNDS FOR DECOMMISSIONING NUCLEAR REACTORS"

Approved X Disapproved _____ Abstain _____

Not Participating _____

COMMENTS: Below ___ Attached X None ___

SIGNATURE

9/28/10

DATE

Entered on "STARS" Yes X No ___

Chairman Jaczko's Comments on SECY-10-0084
Explanation of Changes to Revision 2 to Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors"

I approve the changes to the regulatory guidance concerning the assurance of the availability of decommissioning funds for nuclear reactors. Also, I support the staff's position on the use of net present value method. The changes being made by the staff should enhance confidence that adequate decommissioning funding will be available for the safe and timely decommissioning of nuclear reactors.

The changes are consistent with the Commission's rationale for amending the decommissioning trust requirements in 2002 (67 FR 78350). Because of the economic deregulation of electric utilities, the Commission decided to take a more active oversight role of decommissioning funds to increase assurance that an adequate amount of funds will be available for their intended purpose.

The NRC's decommissioning fund requirements for nuclear power reactors afford licensees a variety of options for ensuring that adequate decommissioning funds are accumulated in a timely manner. It is clear from the material provided by the staff that licensees have readily available options at a reasonable cost (e.g., parent company guarantee) to comply with the decommissioning funding requirements without the need for the licensee to make imprudent adjustments in investment portfolios under challenging market conditions. I commend the staff for not letting concerns for market fluctuations and the possible overreliance of some licensees on one option for the accumulation of funds divert their focus from the protection of the public and the environment. The same way that market fluctuations would not relieve a licensee of its obligation to meet safety regulations, market fluctuations should not be used as a basis by licensees to avoid or delay their obligation to accumulate funds consistent with the regulations.

The changes are consistent with the requirements described in 10 CFR 50.75, which account for licensees that are not rate-regulated or do not have access to a non-bypassable charge for decommissioning. Licensees are required to annually estimate the amount of decommissioning funds needed and every two years report to the NRC the status of its decommissioning fund. The regulations are silent on how quickly a licensee should make up any shortfall that is identified during its annual estimation of the amount of funds needed for decommissioning. The changes are consistent with the timeframes in the requirements. If licensees would like to increase the duration to make up a shortfall beyond the timeframes in the current regulations for the accumulation of funds, then licensees should pursue a petition for rulemaking to avoid creating precedence where regulatory guidance is used as a substitute for regulations.

9/28/10

Gregory B. Jaczko — Date

NOTATION VOTE

RESPONSE SHEET

TO: Annette Vietti-Cook, Secretary

FROM: COMMISSIONER SVINICKI

SUBJECT: SECY-10-0084 – EXPLANATION OF CHANGES TO REVISION 2 TO REGULATORY GUIDE 1.159, "ASSURING THE AVAILABILITY OF FUNDS FOR DECOMMISSIONING NUCLEAR REACTORS"

Approved XX In Part Disapproved XX In Part Abstain _____

Not Participating _____

COMMENTS: Below ___ Attached XX None ___

SIGNATURE

09/13/10

DATE

Entered on "STARS" Yes ✓ No ___

Commissioner Svinicki's Comments on SECY-10-0084
Explanation of Changes to Revision 2 to Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors"

I approve in part and disapprove in part the NRC staff's proposed changes to Revision 2 to Regulatory Guide 1.159. I have followed this issue over the past year, received status briefings from the NRC staff on the issue, reviewed the record of public comment on the draft guidance, and participated in the Commission's public meeting in 2009 on the topic of decommissioning funding. I supported the direction to the staff (Staff Requirements Memorandum M100223B) which required that the staff provide to the Commission an information paper explaining any changes proposed to the final Regulatory Guide 1.159 (to be issued as Revision 2) based on staff's review and assessment of the public comment record. Upon receipt of this information paper by the Commission, I requested that the paper be converted to a notation vote because I reach a different conclusion than the staff on two matters where staff proposes to depart from standing practice. Consequently, I disapprove those particular changes and approve the issuance of Regulatory Guide 1.159, subject to the modifications I describe below.

First, I do not support the proposed change directing merchant licensees to adjust decommissioning funds annually and within 3 months of the annual recalculation of the regulatory minimum required by 10 CFR 50.75(b). The current version of Regulatory Guide 1.159 (Revision 1) states that: "In every case, needed adjustments to the amount of funds set aside should be made at least once every two years, in conjunction with the biennial report, for licensees who are no longer rate regulated or do not have access to a non-bypassable charge ...". This guidance has been interpreted to require that shortfalls identified in a biennial report must be corrected by the time the next biennial report is due two years later. Staff assesses that the outcome of the most recent round of biennial reports (March 2009) provides a basis to conclude that this frequency is insufficient and must be increased.

Laying aside that the reports submitted in March of 2009 captured a snapshot of decommissioning fund performance immediately following one of the most significant market downturns in the country's history, I do not accept that these events, even when coupled with comparisons to the 2003 market downturn, provide a basis to conclude that the NRC's current approach is a failure or that the frequency of adjustments must be significantly accelerated. Even the Nation's highest public policymaking body, the U.S. Congress, through its actions providing statutory relief for pension plan mandatory minimum contributions in 2009, acknowledged the unique market circumstances in existence at that time. Regulatory Guide 1.159 should retain its current directive, requiring adjustment of funding amounts by merchant licensees "at least once every two years, in conjunction with the biennial report," which should be interpreted to require that shortfalls identified in a biennial report must be corrected by the time the next biennial report is due two years later.

Second, I do not support a categorical prohibition on the use of the net present value method for parent guarantees, the use of which has been previously approved by the NRC in license transfer cases. Industry comments on the proposed prohibition take exception to the staff's "flawed logic" comparing the guarantee to a box of money buried in the ground and point out that the guarantee amount would not be buried in a box, but rather, it would be deposited in the decommissioning trust fund, where it could generate earnings just like other assets in the fund. The NRC staff also fundamentally rejects the financial burden associated with carrying parent company guarantees. Substantial differences with the NRC staff view on this point emerge in the public comment record, and I will not repeat them here. Upon evaluating this record, I am

not convinced that the staff has given full consideration to the impacts of a prohibition on the use of the net present value method and this proposed change is not supported by the record. Revision 2 to Regulatory Guidance 1.159 should permit the use of the net present value approach, but only in situations where the licensee can demonstrate that such guarantees supply assurance that is effectively equivalent to prepayment, using an existing approach such as annually recalculating the shortfall amount and adjusting the parent company guarantee amount accordingly.

The staff has taken a very deliberate approach to these two issues, but in weighing the arguments and exercising my policy judgment, I simply reach a different conclusion on whether a change is merited at this time. In the two instances I have outlined here, I assess that the public comment record advances a more fulsome analysis of the issues based on more robust data. Consequently, I do not support the changes advocated by the staff.

Lastly, I am concerned that the overall tone of the staff's response to public comment and the defense of the proposed changes, which occasionally stretched thin data to questionable lengths and which, in one instance, quoted William Shakespeare to justify its rationale, potentially leave the NRC open to charges that it has lost its dispassionate, fact-based perspective in evaluating this issue. These dramatic flourishes clearly depart from the agency's "plain language" objectives when communicating with the broader public about complex regulatory issues and, I fear, leave a dim view of the agency's professionalism in this instance.

Kristine L. Svinicki 9/13/10

NOTATION VOTE

RESPONSE SHEET

TO: Annette Vietti-Cook, Secretary

FROM: Commissioner Apostolakis

SUBJECT: SECY-10-0084 – EXPLANATION OF CHANGES TO REVISION 2 TO REGULATORY GUIDE 1.159, "ASSURING THE AVAILABILITY OF FUNDS FOR DECOMMISSIONING NUCLEAR REACTORS"

Approved XX Disapproved XX Abstain ____

Not Participating ____

COMMENTS: Below XX Attached ___ None ___

I approve in part and disapprove in part the NRC staff's proposed changes to Revision 2 to Regulatory Guide 1.159. I approve issuance of RG 1.159, Revision 2 once the changes proposed by Commissioner Magwood have been incorporated. I support Commissioner Magwood's recommendation that staff engage stakeholders and relevant experts in a workshop to develop an option paper on the use of the net present value approach for Commission consideration.

SIGNATURE

10/13/10
DATE

Entered on "STARS" Yes X No ___

NOTATION VOTE

RESPONSE SHEET

TO: Annette Vietti-Cook, Secretary

FROM: COMMISSIONER MAGWOOD

SUBJECT: SECY-10-0084 – EXPLANATION OF CHANGES TO REVISION 2 TO REGULATORY GUIDE 1.159, "ASSURING THE AVAILABILITY OF FUNDS FOR DECOMMISSIONING NUCLEAR REACTORS"

Approved X Disapproved X Abstain ____

Not Participating ____

COMMENTS: Below ___ Attached X None ___

[signature]
SIGNATURE

8 October 2010
DATE

Entered on "STARS" Yes X No ___

Commissioner Magwoods's Comment ON SECY-10-0084
Explanation of Changes to Revision 2 to Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors

The public has a right to expect that licensees that have been provided authorization to operate nuclear power plants in this country have taken appropriate measures to assure that the ultimate disposition of those facilities will be fully funded whether the plants are shut down this year or fifty years from now. Given that, the agency currently requires licensees to report the status of their decommissioning funds every two years. Any shortfalls in the funds at any given time (which are predicated on regular contributions and growth of investments to achieve stated targets that are generally several decades in the future) must be remediated every six years in the case of rate regulated utilities, or every two years in the case of merchant plants.

Evidence that numerous licensees experienced shortfalls in the face of falling stock prices in recent years (which has been exacerbated by the global recession of 2008-2009) made it appropriate that the agency review its policies and guidelines with respect to D&D funds and, as needed, make appropriate adjustments. In response, staff has recommended several changes to Regulatory Guide 1.159.

I appreciate the staff's efforts to address the challenges associated with assuring the adequacy of decommissioning funds. I believe that the analysis and the engagement with stakeholders has been most helpful in assisting the Commission's evaluation of this matter. That said, I do have concerns with some of the conclusions reached by the staff.

In particular, I note one comment made by the staff in response to an industry comment:

> *Using future market gains to pay for decommissioning transfers the cost from the current beneficiaries of energy production to a future generation. The issue of intergenerational equity argues against heavy reliance on capital gains to fund decommissioning.*
>
> *Finally, as a technical point, reliance on market gains would be difficult to use as a regulatory mechanism. Hope springs eternal that the market will rise quickly in the near future. Waiting for the markets to "sort themselves out" does not appear to have an obvious endpoint to select as regulatory deadline.*[1]

This passage raises a variety of issues. First, I must wonder how any industrial activity in the United States could be planned and implemented if one does not expect economic growth. All licensees operate in a context that anticipates continued (*though certainly not continual*) economic growth in the U.S. I would object to an approach that is predicated on unrealistic

[1] Response to Comments on Draft Guidance DG-1229, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors"

growth projections. But I am loath to accept an approach that is predicated on long-term economic decline.

Moreover, it is obvious that the entire structure of D&D funds is based on the precept that licensees will rely, to some measure, on long-term expansion of the markets and long-term growth of the investments that comprise the fund. We might have otherwise applied a different model for the funds, such as the approach used for Nuclear Waste Fund or by requiring licensees to purchase government bonds. We did not make this choice and despite the recent contraction of the markets and all the tribulations this has wrought, it would be, in my view, inappropriate to slowly rewrite the rules such that the benefits of the current market-based approach are eroded.

I am also concerned by the approach the staff brings to the question of the frequency of adjustments. Staff, for example, proposes to increase the frequency for merchant plants from the current two years to one, based largely on the problems encountered during the recent economic downturn. Based on the staff's analysis of the problem and the logic it presents, I am not certain why we do not consider monthly or weekly adjustments rather than annual adjustments.

As a result of these considerations, I approve publication of the revised regulatory guide but disapprove the proposed change directing merchant licensees to adjust decommissioning funds annually and within 3 months of the annual recalculation of the regulatory minimum required by 10 CFR 50.75(b). I do, however, approve an adjustment for public utility licensees with the understanding that the required adjustment frequency is to be tied to utility rate cases.

Finally, while I believe the staff's analysis is compelling with regard to the use of the net present value approach, I do not feel that the Commission yet has a complete view on this element of the issue. We would benefit from a wider perspective on this complex issue before reaching a final conclusion. Therefore, I recommend that staff engage stakeholders and relevant experts in a workshop to develop an option paper for Commission consideration.

10/8/10

William D. Magwood, IV **Date**

NOTATION VOTE

RESPONSE SHEET

TO: Annette Vietti-Cook, Secretary

FROM: COMMISSIONER OSTENDORFF

SUBJECT: SECY-10-0084 – EXPLANATION OF CHANGES TO REVISION 2 TO REGULATORY GUIDE 1.159, "ASSURING THE AVAILABILITY OF FUNDS FOR DECOMMISSIONING NUCLEAR REACTORS"

Approved X Disapproved X Abstain ____

Not Participating ____

COMMENTS: Below ___ Attached X None ___

[signature]
SIGNATURE

10/14/10
DATE

Entered on "STARS" Yes X No ___

Commissioner Ostendorff's Comments on SECY 10-0084

Explanation of Changes to Revision 2 to Regulatory Guide 1.159,

"Assuring the Availability of Funds for Decommissioning Nuclear Reactors"

I approve in part and disapprove in part the NRC staff's proposed changes to Regulatory Guide 1.159 guidance. I approve Revision 2 of Regulatory Guide 1.159 with two specific exceptions. In assessing the proposed changes and associated Commission direction to address decommissioning fund shortfalls, I appreciate the staff's diligence to address shortfalls in light of the recent deep economic recession. While in the midst of the market decline in 2009, the NRC could not have been omnisciently aware of the magnitude of the economic downturn, the global dependencies involved, and the effectiveness of domestic and international efforts to stabilize financial markets. In retrospect, this economic event was of historic proportions and in comparison to the 2003 recession is not appropriate to gauge the effectiveness of our decommissioning fund assurance expectations of licensees, especially given that recovery has already occurred for the vast majority of reported fund shortfalls. Arguably, the 27 licensees who experienced temporary shortfalls did not jeopardize adequate protection of public health and safety. Hence, some of the proposed changes to Regulatory Guide 1.159 noted below are not fully supportable at this time.

Overall, I concur with Commissioner Svinicki's assessment and recommendation to disapprove the staff's proposed changes in regulatory guidance to have (1) merchant licensees make annual adjustments to reactor decommissioning funds and within 3 months of the annual recalculation of the regulatory minimum required by 10 CFR 50.75(b) and (2) categorical exclusion of net present value (NPV) methods for parent guarantees. The staff should consider whether NRC guidance should provide criteria for reasonable timeframes to resolve shortfalls when a common economic event affects multiple licensees. In the interim, Regulatory Guide 1.159 Revision 2 should retain the current guidance from Revision 1 expecting merchant licensees who need adjustment of funds set aside should make their adjustments at least once every two years, in conjunction with the biennial report. This guidance should be interpreted that reported shortfalls indentified in a biennial report should be corrected by the time the next biennial report is issued. Lastly, future Federal Register Notices (*FRNs*) soliciting public comments on guidance for 10 CFR 50.75 should provide a clear summary of major changes to the guidance. The staff's June 30, 2009 *FRN* on proposed revisions to R.G. 1.159 and the regulatory guide itself did not contain a clear summary of major changes and basis so stakeholders may provide meaningful feedback to the NRC without extensive and detailed examination to identify substantive matters.

William C. Ostendorff 10/ 14 /10

Page 1 of 1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 EAST LAMAR BOULEVARD
ARLINGTON, TEXAS 76011-4511

December 19, 2018

EA-18-155

Mr. Doug Bauder
Vice President and Chief Nuclear Officer
Southern California Edison Company
San Onofre Nuclear Generating Station
P.O. Box 128
San Clemente, CA 92674-0128

SUBJECT: ERRATA: SAN ONOFRE NUCLEAR GENERATING STATION - NRC SPECIAL INSPECTION REPORT 050-00206/2018-005, 050-00361/2018-005, 050-00362/2018-005, 072-00041/2018-001 AND NOTICE OF VIOLATION

Mr. Bauder:

It was identified that the U.S. Nuclear Regulatory Commission (NRC) Special Inspection Report No. 050-00206/2018-005, 050-00361/2018-005, 050-00362/2018-005, 072-00041/2018-001, dated November 28, 2018 Agency Document and Management System (ADAMS) (ADAMS Accession No. ML18332A357) and Notice of Violation (Notice) incorrectly identified the cited violation against 10 CFR 72.192, regarding "Operator training and certification program," in lieu of citing the violation against 10 CFR 72.190, "Operator requirements." The corrected inspection report and Notice shall refer to "10 CFR 72.190" in all applicable areas. As specified in 10 CFR 72.13, the regulation identified under 10 CFR 72.190 is applicable to a general licensee, which is the type of license held by Southern California Edison Company. The inspection report and all its enclosures, including the Notice, is reissued in its entirety under the same inspection report number and is enclosed.

The change to the citation in the Notice involving training and certification of personnel does not change the content of the inspection report, or the two apparent violations. As such, the communications provided in the November 28, 2018, inspection report regarding your opportunity to request a predecisional enforcement conference (PEC) or alternative dispute resolution (ADR) remains in effect from the date of the original inspection report, November 28, 2018. On December 10, 2018, SONGS informed the NRC that it requested a PEC. My staff is working with your staff to schedule the PEC.

In accordance with 10 CFR 2.390 of the NRC's "Agency Rules of Practice and Procedure," a copy of this letter, its enclosures, and your response (if any), will be made available electronically for public inspection in the NRC Public Document Room and from the NRC's ADAMS, accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

If you have any questions concerning this matter, please contact Dr. Janine F. Katanic, CHP, of my staff at 817-200-1151.

Sincerely,

/RA/

Troy W. Pruett, Director
Division of Nuclear Materials Safety

Docket Nos.: 50-206; 50-361; 50-362; 72-041
License Nos.: NPF-10; NPF-15; DPR-13

Enclosure:
Revised NRC Special Inspection
Report 050-00206/2018-005,
050-00361/2018-005, 050-00362/2018-005,
and 072-00041/2018-001

ERRATA: SAN ONOFRE NUCLEAR GENERATING STATION - NRC SPECIAL INSPECTION REPORT 050-00206/2018-005, 050-00361/2018-005, 050-00362/2018-005, 072-00041/2018-001 AND NOTICE OF VIOLATION – DATED DECEMBER 19, 2018

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ADAMS PACKAGE NUMBER: ML18341A162
ADAMS ERRATA ACCESSION NUMBER: ML18341A172

■ SUNSI Review By: EJS	ADAMS: ■ Yes ☐ No	☐ Sensitive ■ Non-Sensitive	☐ Non-Publicly Available ■ Publicly Available	Keyword NRC-002

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SAN ONOFRE NUCLEAR GENERATING STATION
NRC SPECIAL INSPECTION REPORT 050-00206/2018-005,
050-00361/2018-005, 050-00362/2018-005, 072-00041/2018-001
AND REVISED NOTICE OF VIOLATION
(ML18341A172)

Enclosure

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 EAST LAMAR BOULEVARD
ARLINGTON, TEXAS 76011-4511

December 19, 2018

EA-18-155

Mr. Doug Bauder
Vice President and Chief Nuclear Officer
Southern California Edison Company
San Onofre Nuclear Generating Station
P.O. Box 128
San Clemente, CA 92674-0128

SUBJECT: REVISED NRC SPECIAL INSPECTION REPORT 050-00206/2018-005, 050-00361/2018-005, 050-00362/2018-005, 072-00041/2018-001 AND REVISED NOTICE OF VIOLATION

Mr. Bauder:

This letter refers to the Special Inspection conducted on September 10-14, 2018, at your facility in San Clemente, California. The inspection was conducted in response to the misalignment of a loaded spent fuel storage canister as it was being downloaded into the storage vault at the San Onofre Nuclear Generating Station (SONGS). Based on the criteria specified in Management Directive 8.3, "NRC Incident Investigation Program," the Nuclear Regulatory Commission (NRC) initiated a Special Inspection in accordance with Inspection Procedure 93812, "Special Inspection." The basis for initiating the Special Inspection and the focus areas for review are detailed in the Special Inspection Charter (Enclosure 3), dated August 17, 2018 (Agencywide Document Access and Management System (ADAMS) Accession ML18229A203).

The enclosed report documents the results of the inspection. The inspectors discussed the preliminary inspection findings with Mr. Thomas Palmisano and members of your staff on September 14, 2018, at the conclusion of the onsite portion of the inspection. A final exit briefing was conducted telephonically with Mr. Palmisano and members of your staff on November 1, 2018.

Based on the results of the Special Inspection, two apparent violations were identified and are being considered for escalated enforcement action in accordance with the NRC Enforcement Policy. The current Enforcement Policy is included on the NRC Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html. The circumstances surrounding these apparent violations, the significance of the associated issues, and the need for corrective actions were discussed with Mr. Palmisano at the conclusion of the onsite inspection and during the final telephonic exit briefing. The apparent violations involved the failure to: (1) ensure important-to-safety equipment was available to provide redundant drop protection features for a spent fuel canister during downloading operations; and (2) make a timely notification to the NRC Headquarters Operations Center for the August 3, 2018, disabling of important-to-safety equipment.

The NRC is concerned about apparent weaknesses in management oversight of the dry cask storage operations. Your staff did not perform adequate direct observational oversight of downloading activities performed by your contractor, ensure adequate training of individuals responsible for performing downloading operations, provide adequate procedures for downloading operations, or ensure that conditions adverse to quality were entered into the corrective action program. The NRC identified that a causal factor for the misalignment incident involved management weakness in the oversight of dry cask storage operations.

Before the NRC makes its enforcement decision, we are providing you with an opportunity to: (1) request a predecisional enforcement conference (PEC) or (2) request alternative dispute resolution (ADR). If a PEC is held, it will be open for public observation and the NRC will issue a press release to announce the time and date of the conference.

If you choose to request a PEC, the conference will afford you the opportunity to provide your perspective on these matters and any other information that you believe the NRC should take into consideration before making an enforcement decision. The decision to hold a PEC does not mean that the NRC has determined that a violation has occurred or that enforcement action will be taken. This conference would be conducted to obtain information to assist the NRC in making an enforcement decision.

The topics discussed during the conference may include information to determine whether a violation occurred, information to determine the significance of a violation, information related to the identification of a violation, and information related to any corrective actions taken or planned. In presenting your corrective actions, you should be aware that the promptness and comprehensiveness of your actions will be considered in assessing any civil penalty for the apparent violations. The guidance in NRC Information Notice 96-28, "Suggested Guidance Relating to Development and Implementation of Corrective Action," may be helpful and can be obtained at the NRC Web site at http://pbadupws.nrc.gov/docs/ML0612/ML061240509.pdf.

In lieu of a PEC, you may also request ADR with the NRC in an attempt to resolve this issue. Alternative dispute resolution is a general term encompassing various techniques for resolving conflicts using a neutral third party. The technique that the NRC has decided to employ is mediation. Mediation is a voluntary, informal process in which a trained neutral mediator works with parties to help them reach resolution. If the parties agree to use ADR, they select a mutually agreeable neutral mediator who has no stake in the outcome and no power to make decisions. Mediation gives parties an opportunity to discuss issues, clear up misunderstandings, be creative, find areas of agreement, and reach a final resolution of the issues.

Additional information concerning the NRC's program can be obtained at http://www.nrc.gov/about-nrc/regulatory/enforcement/adr.html. The Institute on Conflict Resolution at Cornell University has agreed to facilitate the NRC's program as a neutral third party. Please contact the Institute on Conflict Resolution at 877-733-9415 within 10 days of the date of this letter if you are interested in pursuing resolution of these issues through ADR. Alternative dispute resolution sessions are not conducted with public observation though the outcome of the ADR agreement is made public.

A PEC should be held within 30 days and an ADR session within 45 days of the date of this letter. Please contact Dr. Janine F. Katanic at 817-200-1151 within 10 days of the date of this letter to notify the NRC of your intended response.

In addition, please be advised that the number and characterization of apparent violations described in the enclosed inspection report may change as a result of further NRC review. You will be advised by separate correspondence of the results of our deliberations on this matter.

The NRC determined that three Severity Level IV violations of NRC requirements occurred. These violations were evaluated in accordance with Section 2.2.2 of the NRC Enforcement Policy. The NRC determined the issuance of a Notice of Violation (Notice) is appropriate because the actions to restore compliance have not been fully developed and implemented, and the actions must be effective prior to beginning fuel handling activities.

The three Severity Level IV violations are cited in the enclosed Notice and the circumstances surrounding them are described in detail in the subject inspection report. The violations involved failures to: (1) identify conditions potentially adverse to quality for placement into your corrective actions program; (2) assure that operations of important to safety equipment were limited to trained and certified personnel or under direct supervision; and (3) provide adequate procedures for dry cask storage operations involving downloading operations.

In accordance with 10 CFR 2.390 of the NRC's "Agency Rules of Practice and Procedure," a copy of this letter, its enclosures, and your response, will be made available electronically for public inspection in the NRC Public Document Room and from the NRC's ADAMS, accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response should not include any personal privacy or proprietary information so that it can be made available to the public without redaction.

If you have any questions concerning this matter, please contact Dr. Janine F. Katanic, CHP, of my staff at 817-200-1151.

Sincerely,

/RA/

Troy W. Pruett, Director
Division of Nuclear Materials Safety

Docket Nos.: 50-206; 50-361; 50-362; 72-041
License Nos.: NPF-10; NPF-15; DPR-13

Enclosures:
1. Notice of Violation
2. Revised NRC Special Inspection Report 050-00206/2018-005, 050-00361/2018-005, 050-00362/2018-005, and 072-00041/2018-001
3. Special Inspection Charter dated August 17, 2018 (ML18229A203)

NOTICE OF VIOLATION

Southern California Edison Company San Clemente, CA		Docket Nos.:	050-00206, 050-00361, 050-00362, 072-00041
		License Nos.:	NPF-10; NPF-15; DPR-13
		EA No:	18-155

During an NRC Special Inspection conducted September 10 through November 1, 2018, three violations of NRC requirements were identified. In accordance with the NRC Enforcement Policy, the violations are listed below:

A. 10 CFR 72.172 requires, in part, that, licensees establish measures to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, and deviations, are promptly identified and corrected.

   Contrary to the above, from January 30 to August 3, 2018, the licensee failed to establish measures to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, and deviations, were promptly identified and corrected. Specifically:

   1. On July 22, 2018, the loading crew experienced difficulty in aligning canister 28 for downloading into the independent spent fuel installation vault. However, the licensee failed to enter this deviation in downloading conditions into its corrective action program to determine the cause of the misalignment problem and develop corrective actions to preclude reoccurrence.

   2. From January 30 to August 3, 2018, during canister downloading, contact between the canister and vault components frequently occurred. However, the licensee failed to enter instances of contact into its corrective action program and perform an assessment to disposition the exterior conditions of the downloaded canisters and vault components.

This is a Severity Level IV violation (NRC Enforcement Policy Section 6.3).

B. 10 CFR 72.190 requires, in part, that the operation of equipment and controls that have been identified as important to safety in the Safety Analysis Report and in the license must be limited to trained and certified personnel or be under the direct supervision of an individual with training and certification in the operation. The HI-STORM UMAX SYSTEM Final Safety Analysis Report (FSAR), Revision 4, dated August 14, 2017, specifies, in part, that the operations at the independent spent fuel storage installation are governed by the HI-STORM FW SYSTEM FSAR, Revision 5, dated June 20, 2017, which specifies that the multipurpose canister lifting slings and multipurpose canister lift attachments are designated as important to safety equipment.

   Contrary to the above, from January 30 to August 3, 2018, the licensee failed to assure that operations of equipment and controls that had been identified as important to safety in the Safety Analysis Report were limited to trained and certified personnel or were under the direct supervision of an individual with training and certification in the operation. Specifically:

1. The training program failed to adequately train and certify the rigger/spotter position involved in the important to safety downloading operation.

2. The training program for the vertical cask transporter operator position failed to have adequate proficiency testing, on the controls related to the load indicating device and downloading operations.

This is a Severity Level IV violation (NRC Enforcement Policy Section 6.3).

C. 10 CFR 72.150, requires, in part, that the licensee prescribe activities affecting quality by documented instructions or procedures of a type appropriate to the circumstances and must include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

   Contrary to the above, from January 30 to August 3, 2018, the licensee failed to prescribe activities affecting quality by documented instructions or procedures of a type appropriate to the circumstances and include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Specifically:

   1. Procedure HPP-2464-400, "Multi-Purpose Canister Transfer at SONGS," Revision 15, step 7.6.23, failed to provide qualitative and quantitative directions for the vertical cask transporter operator to monitor control panel indications that would identify a canister had become misaligned during downloading operation.

   2. Procedure HPP-2464-400, "Multi-Purpose Canister Transfer at SONGS," Revision 15, step 7.6.23, failed to include adequate instructions for the rigger/spotter to monitor the downloading slings for a slack condition.

This is a Severity Level IV violation (NRC Enforcement Policy Section 6.3).

Pursuant to the provisions of 10 CFR 2.201, Southern California Edison Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 1600 E. Lamar Blvd., Arlington, TX 76011, within 30 days of the date of the letter transmitting this Notice of Violation (Notice).

This reply should be clearly marked as a "Reply to a Notice of Violation, EA-18-155" and should include, for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level; (2) the corrective steps that have been taken and the results achieved; (3) the corrective steps that will be taken; and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued requiring information as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

Your response will be made available electronically for public inspection in the NRC Public Document Room or in the NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response should not include any personal privacy or proprietary information so that it can be made available to the public without redaction.

If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information).

Dated this 19th day of December 2018

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-206; 50-361; 50-362; 72-041
License Nos.:	NPF-10; NPF-15; DPR-13
Report No.:	050-00206/2018005; 050-00361/2018005; 050-00362/2018005; and 072-00041/2018001
Enterprise Identifier:	I-2018-001-0138
EA No.:	18-155
Licensee:	Southern California Edison Company
Location:	San Clemente, CA 92674-012
Inspection Dates:	Onsite September 10-14, 2018 In-office review through November 1, 2018
Exit Meeting Date:	November 1, 2018
Inspectors:	Eric Simpson, CHP, Health Physicist Fuel Cycle and Decommissioning Branch Division of Nuclear Materials Safety, Region IV Marlone Davis, Senior Inspector Inspections and Operations Branch Division of Spent Fuel Management W. Chris Smith, Reactor Inspector Engineering Branch 1 Division of Reactor Safety, Region IV
Accompanied By:	Janine F. Katanic, PhD, CHP, Chief Fuel Cycle and Decommissioning Branch Division of Nuclear Materials Safety, Region IV Patricia Silva, Chief Inspections and Operations Branch Division of Spent Fuel Management Troy W. Pruett, Director Division of Nuclear Materials Safety, Region IV
Approved By:	Troy W. Pruett, Director Division of Nuclear Materials Safety, Region IV
Attachment:	Supplemental Inspection Information

Enclosure 2

EXECUTIVE SUMMARY

NRC Special Inspection Report 050-00206/2018005; 050-00361/2018005; 050-00362/2018005; and 072-00041/2018-001

On September 10-14, 2018, the U.S. Nuclear Regulatory Commission performed an announced Special Inspection of the independent spent fuel storage installation at the decommissioning San Onofre Nuclear Generating Station in San Clemente, California. The inspection continued with an in-office review of training material, licensee analyses, procedures, and other materials gathered during the onsite inspection through November 1, 2018. The Southern California Edison Company, the licensee and owner of San Onofre Nuclear Generating Station, has an NRC General License for its independent spent fuel installation under Title 10 of the *Code of Federal Regulations* (10 CFR) Part 72. The scope of the inspection was to evaluate the facts and circumstances involved in the August 3, 2018, misalignment incident, and review the licensee's follow-up investigation, causal evaluation, and planned corrective actions.

NRC Special Inspection of San Onofre Nuclear Generating Station Canister Misalignment Incident of August 3, 2018

- The licensee's actions that led to disabling the important to safety downloading slings and removal of redundant drop protection features were identified as an apparent violation of Technical Specification 5.2.c.3 requirements. (Section 3.1.1)

- The NRC team identified missed opportunities where the licensee could have addressed the potential for a downloading misalignment. For example, on July 22, 2018, one of the crews experienced misalignment difficulty resulting in a prolonged downloading operation. The licensee did not enter the adverse condition into the corrective action program to determine the cause and develop appropriate corrective actions. This was identified as a Severity Level IV violation of 10 CFR 72.172 requirements. (Section 3.1.1)

- Personnel lacked the proper training, proficiency testing, and certifications to operate important to safety equipment identified in the HI-STORM UMAX SYSTEM Final Safety Analysis Report, Revision 4, dated August 14, 2017. This was identified as a Severity Level IV violation of 10 CFR 72.190 requirements. (Section 3.1.2)

- Dry cask storage procedures did not provide adequate directions for how to determine the downloader slings were slack. Slack in the slings was an indicator of a loss-of-load. Further, procedures did not include qualitative or quantitative means to determine when a canister had become misaligned. These procedure inadequacies were identified as a Severity Level IV violation of 10 CFR 72.150 requirements. (Section 3.1.3)

- No licensee or contractor oversight staff were in direct visual observation of important to safety activities during downloading operations on August 3, 2018. Licensee oversight was not a part of communications between the cask loading supervisor, the rigger/spotter, and vertical cask transporter operator during downloading operations. (Section 3.1.3)

- The licensee concluded and the NRC agreed that the minor removal of divider shell coating during downloading operations did not affect the design functions for shielding, structural, and thermal safety functions. The licensee's plan to address future inspection of the divider shells in their aging management program is acceptable. (Section 3.1.4)

- The licensee failed to make the required 24-hour NRC notification of the August 3, 2018, incident where important to safety equipment was disabled when required to mitigate the consequences of an accident and no redundant equipment was available to perform the safety function. This failure was identified as an apparent violation of 10 CFR 72.75(d) requirements. (Section 3.1.4)

- The causal evaluations performed by the licensee and its contractor identified apparent and root causes for the August 3, 2018, canister misalignment incident that included inadequate training, inadequate procedures, poor utilization of the corrective action program, and insufficient management oversight. (Section 3.1.5)

- The licensee's consequence analysis resulting from a hypothetical 25-foot canister drop determined that the canister integrity would be maintained. The NRC will continue to inspect the licensee's consequence analysis. (Section 3.1.5)

- The licensee provided an analysis to demonstrate that wear on canister 29 during the downloading incident would meet established acceptance criteria. The NRC determined that more analysis was required to accept that the canister meets design requirements. This charter item will be reviewed during a future NRC inspection. (Section 3.1.6)

- All associated corrective actions for the August 3, 2018, incident had not been fully developed and implemented by the licensee. The NRC will review the licensee's revised procedures, training plans, equipment modifications, and performance testing (dry runs) of its dry cask storage operations during a future inspection to determine the effectiveness of corrective actions for the incident. (Section 3.1.7)

REPORT DETAILS

1 Inspection Scope

On September 10-14, 2018, the NRC performed an announced Special Inspection at the San Onofre Nuclear Generating Station (SONGS) in San Clemente, California, which was followed by in-office reviews of additional information provided by the licensee through November 1, 2018. The scope of the inspection was to interview personnel associated with the August 3, 2018, misalignment incident to independently evaluate the circumstances of the canister misalignment; identify and review all pertinent records, documents, and procedures related to the licensee's downloading operations; evaluate procedure adequacy and adherence; evaluate the reportability requirements; and to evaluate the root cause analyses and corrective actions to prevent recurrence.

2 Background

2.1 General Description of Multi-purpose Canister Downloading Operations

On November 8, 2018, the NRC conducted a public meeting webinar (NRC's Agencywide Documents Access and Management System (ADAMS) Accession ML18319A139). The presentation provides a summary of a downloading operation.

A vertical cask transporter (VCT) is used for transporting the transfer cask and multi-purpose canister (MPC or canister) loaded with spent fuel onto the independent spent fuel storage installation (ISFSI) pad. Dry cask storage workers manipulate the VCT to align the transfer cask over the ISFSI vertical ventilated module (VVM or vault) in which the canister will be stored. Once alignment has been achieved and the transfer cask is securely bolted to a mating device, the transfer cask is disconnected from the VCT. Lifting slings are connected to the top of the canister and the VCT overhead lift beam. The VCT lift beam is raised until the load of the canister is supported and no longer resting on the bottom of the transfer cask.

While the canister is being supported by the lift beam and slings, a drawer on the mating device is opened. Once the drawer is open, the VCT operator lowers the lift beam, which lowers the canister into the storage vault. The VCT can be moved during the download to make fine adjustments for canister alignment within the vault. While the canister is being lowered, it passes through a divider shell assembly. The divider shell has a shield ring that the canister must pass through as it is being lowered into the vault. When fully downloaded, the canister will be seated on a pedestal in the cavity enclosure container in the vault.

2.2 August 3, 2018 Canister Misalignment

On August 3, 2018, as the loaded canister was being lowered into the vault, personnel failed to notice that the canister was misaligned. The licensee and its contractor continued to lower the VCT lift beam until staff believed that the canister had been fully lowered to the bottom of the vault. Staff involved in the download failed to recognize the lifting slings were slack. A radiation protection technician identified radiation readings that were not consistent with a fully lowered canister. The licensee then identified that the loaded spent fuel canister was resting on a shield ring near the top of the vault,

preventing it from being lowered, and that the rigging and lifting slings were slack and no longer bearing the load of the canister.

With the slings slack, the lifting equipment was no longer capable of performing it's important to safety function of holding and controlling the loaded canister. The canister could have experienced an approximately 17-18 foot drop into the storage vault if the canister had slipped off the shield ring. This load drop accident is not a condition analyzed in the dry fuel storage system's Final Safety Analysis Report (FSAR).

The licensee restored the control of the load to the slings and lifting devices. The estimated time the canister was in an unsupported position was approximately 45 minutes. The licensee repositioned and lowered the canister into the vault. The licensee subsequently halted all dry fuel storage movement operations in order to fully investigate the incident and develop corrective actions to prevent recurrence.

The licensee informed Region IV staff of the misalignment incident on August 6, 2018. Region IV discussed the licensee's plans for evaluation and follow-up for the incident and the status of fuel loading operations. The licensee agreed to suspend fuel loading operations until such time as their senior management was satisfied with their corrective actions, the NRC completed their inspection, and the NRC determines that corrective actions are sufficient to prevent a similar occurrence. Region IV chartered a Special Inspection Team to review the incident, any relevant background information, causal and risk assessments conducted by the licensee, and proposed and completed corrective actions.

3 Special Inspection Charter (IP 93812)

3.1 Inspection Scope

Following the notification to NRC Region IV of the August 3, 2018, misalignment incident, the NRC evaluated the information provided against the criteria for a reactive inspection. Based on the criteria in Management Directive 8.3, "NRC Incident Investigation Program," and Inspection Manual Chapter 0309, "Reactive Inspection Decision Basis for Reactors," a decision was made to perform a Special Inspection. The Special Inspection Charter is provided in Enclosure 3.

The Special Inspection was conducted onsite from September 10-14, 2018, and continued with in-office review until November 1, 2018. The Special Inspection focused on understanding the August 3, 2018, misalignment incident. The inspection included interviewing personnel involved in the incident, developing a timeline, and assessing the licensee's immediate corrective actions.

The sections below provide inspection details for each of the Special Inspection Charter items.

3.1.1 Charter Item 5

Inspection Scope

"Interview personnel associated with the August 3, 2018, misalignment incident to develop a timeline to ensure the licensee's investigation contained all necessary information to identify all contributing factors and develop adequate corrective actions."

The NRC team interviewed licensee and contractor staff involved or present during the August 3, 2018, misalignment incident. The NRC also reviewed records related to dry cask storage operations.

Observations and Findings

Based on interviews and records reviewed, the following timeline was developed:

Date/Time (± 30 minutes)	Activity
August 3, 2018	
12:40 p.m.	Downloading begins for canister 29: All dry cask storage supervision and licensee oversight, including radiation protection staff exited the ISFSI pad to stand in a low-dose area on the ISFSI pad ramp (approximately 150 feet away from the operations). Only the rigger/spotter in the motor-powered boom lift device man-basket (JLG) and the VCT operator remained on the ISFSI pad.
1:05 p.m.	VCT operator and rigger/spotter notify cask loading supervisor (CLS) that the canister has been fully lowered into the ISFSI vault.
1:12 p.m.	The radiation protection technician (RPT) determines radiation levels indicate that the canister was not fully lowered. Work activities were stopped to plan recovery actions with the radiation protection supervisor and CLS. The rigger in charge (RIC) began making preparations to enter the JLG.

1:15 p.m.	Notifications were made to Holtec management.
	The RIC was escorted to the JLG by an RPT.
	The RIC recognized the downloading slings were slack and bundled on the ground near the base of the VCT.
1:33 p.m.	The RIC observed the top of the canister was about 4 feet from the top of the transfer cask and not lowered into the vault.
	The RIC directed the VCT operator to lift the canister.
1:41 p.m.	The canister load was fully supported by the VCT and downloading slings.
1:50 p.m.	An alternate CLS arrived and began to direct operations for downloading to the VCT operator.
	The alternate CLS and RIC noted that during downloading operations the canister experienced interference twice and had to be re-aligned.
2:22 p.m.	Downloading operations completed.
6:00 p.m.	Licensee places hold on all lifting operations.
August 6, 2018	At approximately 4 pm (CDT), the licensee informally contacted NRC Region IV to discuss the August 3, 2018, misalignment incident.
August 7, 2018	NRC Region IV and licensee management agreed that ISFSI operations would cease until the NRC performed an inspection and reviewed the licensee's corrective actions to resume work.
September 14, 2018	At 4 pm (ET) the licensee made a formal notification per 10 CFR 72.75(d)(1) to the NRC Headquarters Operations Center regarding the August 3, 2018, misalignment incident.

Violation of 10 CFR 72.172, Corrective Actions

Interviews with Williams Industrial Services Group and Sonic Systems (Holtec International subcontractors) employees indicated that of a loss-of-load condition or a canister misalignment issue was experienced during dry run evolutions and known to several dry cask storage workers. The Special Inspection team identified a prior canister misalignment issue that occurred on July 22, 2018, in which downloading operations lasted 90 minutes, instead of the expected 15 minutes for downloading canister 28. This incident was documented in a Production Traveler. A Production Traveler is a document that the licensee uses to track the performance of dry fuel storage operations by the

contractor, Holtec International. The Production Travelers were used to track how well the contractor was providing their contracted services to the licensee. The licensee did not enter this condition adverse to quality into its corrective action program.

Licensee oversight generally waited for Holtec staff to initiate a field condition report (FCR) before writing a corresponding condition report. In the Production Traveler for canister 28, the 90 minute delay was related to adjustments that were needed for the VCT towers as canister weight started to lower prematurely before the downloading was complete. This type of misalignment also occurred during the August 3, 2018, incident. On July 22, 2018, the downloading crew for canister 28, noted the reduction in the canister weight and corrected the alignment error. The canister was never unsupported by the slings. No condition report or FCR was generated by either the licensee or contractor.

Through interviews with licensee and contractor staff, the NRC determined that between January 30 and August 3, 2018, the downloading activity often involved contact between the canister and other vault components during downloading. The licensee and its contractor did not enter the misalignment and contact events into the corrective action program. Consequently, actions to assess and disposition the exterior conditions of the downloaded canisters and other components within the vault, such as the divider shell assembly, were not performed. The licensee is responsible to ensure the important to safety components continue to meet their original design criteria and address any aging management concerns the changes could impact. Any deviations, such as scratches or removal of coatings are required to be evaluated to ensure the deviations are not detrimental to the system.

Interviews with individuals involved in dry cask loading operations in August 2018, revealed that the difficulty in aligning the canister was not shared with others, nor was it incorporated into procedures or formal training programs. The VCT operator and the rigger/spotter in charge of downloading operations during the August 3, 2018, incident indicated that they did not know until afterwards that the condition they experienced was something that should have been anticipated.

Title 10 CFR 72.172 requires, in part, that, licensees establish measures to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, and deviations are promptly identified and corrected. Contrary to the above, the licensee failed to establish measures to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, and deviations were promptly identified and corrected. Specifically:

1. On July 22, 2018, the crew experienced difficulty in aligning canister 28 for downloading into the ISFSI vault. However, the licensee failed to enter this deviation in downloading conditions into its corrective action program to determine the cause of the misalignment problem and develop corrective actions to preclude reoccurrence.

2. From January 30 to August 3, 2018, during canister downloading, contact between the canister and the vault components frequently occurred. The licensee failed to enter instances of contact into its corrective action program and perform an assessment to disposition the exterior conditions of the downloaded canisters and vault components.

The team determined that this violation was more than minor because the failure to implement corrective actions contributed to the misalignment incident of August 3, 2018. Additionally, the failure to evaluate and disposition wear marks on a canister, if left uncorrected, could impact the adequacy of the aging management program. The Special Inspection team assessed and dispositioned this violation in accordance with Section 2.2.2 of the NRC Enforcement Policy. The team characterized the violation as a Severity Level IV violation. The NRC determined the issuance of a Notice is appropriate because the actions to restore compliance have not been fully developed and implemented, and the actions must be effective prior to beginning fuel handling activities. (VIO 07200041/2018-001-01, Failure to identify and correct conditions adverse to quality)

Apparent Violation of Technical Specification 5.2.c.3, Redundant Lifting Equipment

On August 3, 2018, the licensee performed operations involving movement of a loaded spent fuel storage canister into its ISFSI vault. As the loaded spent fuel canister was being lowered into the vault, licensee and contractor personnel failed to notice that the canister was misaligned and the weight of the canister was not being supported by the redundant important to safety slings (See Sections 2.1 and 2.2).

Title 10 CFR 72.212(b)(3) requires, in part, that each cask used by the general licensee conforms to the terms, conditions, and specifications of a Certificate of Compliance listed in 10 CFR 72.214. Title 10 CFR 72.214 includes a list of all the approved spent fuel storage casks that can be utilized under the conditions specified in a specific Certificate of Compliance, including Amendment 2 of Certificate of Compliance 072-01040. Certificate of Compliance 072-01040, Amendment 2, Condition 4, "HEAVY LOADS REQUIREMENTS," requires that lifting operations outside of structures governed by 10 CFR Part 50 must be in accordance with Technical Specifications, Appendix A, Section 5.2.

Technical Specification, Appendix A, Section 5.2.c.3 requires that the transfer cask, when loaded with spent fuel, may be lifted and carried at any height during multi-purpose canister transfer operations provided the lifting equipment is designed with redundant drop protection features which prevent uncontrolled lowering of the load.

Contrary to the above, on August 3, 2018, the licensee failed to ensure that redundant drop protection features were available to prevent uncontrolled lowering of the load. Specifically, the licensee inadvertently disabled the redundant important to safety downloading slings while lowering canister 29 into the storage vault. During the approximately 45 minute time-frame, the canister rested on a shield ring unsupported by the redundant downloading slings at approximately 17-18 feet above the fully seated position. This failure to maintain redundant drop protection placed canister 29 in an unanalyzed condition because the postulated drop of a loaded spent fuel canister is not analyzed in the FSAR.

The licensee's failure to ensure the system's designed redundant drop protection features were available to prevent uncontrolled lowering of the loaded canister was identified as an apparent violation of Technical Specification 5.2.c.3.
(AV 07200041/2018-001-02, Failure to ensure redundant drop protection features are available)

Conclusions

The licensee failed to adequately implement the corrective action program for ISFSI operations. This failure resulted in missed opportunities to resolve misalignment errors during canister downloading operations between January 30 and August 3, 2018, and a violation of 10 CFR 72.172.

On August 3, 2018, the licensee failed to recognize that a misalignment of a canister during downloading operations caused redundant drop protection (slings) to be disabled and an apparent violation of Technical Specification 5.2.c.3.

3.1.2 Charter Item 1

Inspection Scope

"Identify and review all pertinent records, documents, and procedures related to the licensee's downloading operations at the ISFSI pad including but not limited to: worker training and qualifications; rigging equipment qualification, testing, and preventative maintenance; and lifting equipment qualification, testing, and preventative maintenance. Evaluate the adequacy of the above noted procedures, worker training, and equipment testing and preparation."

The Special Inspection team reviewed licensee rigging procedures and NUREG-0612 "Control of Heavy Loads at Nuclear Power Plants," training modules. The team reviewed the qualifications for the dry cask storage workers including the records for the workers involved in the August 3, 2018, misalignment incident. The team reviewed the inspection and maintenance records for special lifting devices used during dry fuel storage operations and the qualification records for rigging equipment. The team reviewed procedures used during canister downloading operations.

Observations and Findings

The equipment used for dry cask storage operations met applicable inspection requirements specified in the Holtec HI-STORM UMAX FSAR. The special lifting devices used to transport the transfer cask and to perform downloading operations were designed and tested according to American National Standards Institute (ANSI) N14.6, "American National Standard for Radioactive Materials – Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds or More." The slings used during downloading had a sufficient load rating for the maximum credible load imposed by the canister. The slings were tested according to the safety requirements of American Society of Mechanical Engineers (ASME) B30.9, "Slings." The purchase specifications, qualifications, and maintenance records for the VCT, downloading slings, canister lift cleats, lift lugs, and lift links were satisfactory.

Violation of 10 CFR 72.190, Training and Certification Qualifications

The NRC team reviewed the qualifications of workers involved in the August 3, 2018, incident. Interviews with the individuals primarily responsible for verifying that the canister was properly downloaded into the ISFSI vault showed that the licensee's training program was inadequate for the positions that are designated as rigger/spotter and VCT operator. The VCT operator training program qualifications did not establish

adequate required proficiency training exercises for downloading operations. The VCT operator on August 3, 2018, had never been tested on or exercised with the canister simulator during a pre-operational testing, “dry run” downloading operation. The August 3, 2018, misalignment incident was the first time the VCT operator had actually completed downloading operations as the VCT operator.

Neither the rigger/spotter nor VCT operator was properly trained in determining a loss-of-load condition during downloading operations. The VCT operator stated that he was knowledgeable of the VCT human-machine interface (HMI) screens and that indications provided a digital reading that could allow the operator to determine if the canister was not supported by the slings. However, the VCT operator stated that he did not use the VCT HMI screen to monitor the load of the canister at any time during the August 3, 2018, downloading operations. The VCT operator indicated that he only utilized the HMI screen to determine how evenly the VCT lift beam was descending.

From his position on the VCT, the VCT operator could not see the canister downloader slings. The only indication of a loss-of-load would come from monitoring the VCT hydraulic beam pressure digital reading on the VCT HMI screen, which was not performed. Since the operator had not performed any proficiency training with the VCT during a dry run downloading operation, the individual was inexperienced with the use of the HMI screen to monitor load loss.

The licensee’s training program did not provide a formal process to be qualified for the rigger/spotter position during downloading operations. The rigger/spotter stated that he was not trained on and did not know his roles and responsibilities during the downloading evolution. The August 3, 2018, misalignment incident was the first time the rigger/spotter had attempted to perform downloading operations as the rigger/spotter in the JLG.

The NRC team’s interview with the foreman indicated that the rigger/spotter was selected primarily because of his low accumulated radiation dose. From interviews with licensee and contractor staff, an experienced RIC was usually the individual placed in the JLG and acted as the rigger/spotter for the downloading operations. On August 3, 2018, it was the RIC who eventually entered the JLG after the misalignment and directed the VCT operator to lift the canister with the VCT lift beam to regain the load on the slings. The RIC had immediately recognized that the canister was not downloaded into the ISFSI vault when he arrived and saw the condition of the downloader slings.

The failure to ensure operators are adequately qualified and proficiency tested when operating important to safety equipment and directing critical lift operations is a performance deficiency. The licensee’s training program that allowed the rigger/spotter and VCT operator to be placed into a situation where their lack of training rendered them incapable of meeting the requirements for the job represented a failure of the licensee’s training program.

Title 10 CFR 72.190 requires, in part, that the operation of equipment and controls that are identified as important to safety in the Safety Analysis Report must be limited to trained and certified personnel or be under the direct supervision of an individual with training and certification in the operation. The HI-STORM UMAX SYSTEM FSAR, Revision 4, dated August 14, 2017, specifies, in part, that the operations at the ISFSI are

governed by the HI-STORM FW SYSTEM FSAR, Revision 5, dated June 20, 2017, which specifies that the MPC lifting slings and MPC lift attachments are designated as important to safety equipment. Contrary to the above, from January 30 to August 3, 2018, the licensee failed to assure that operations of equipment and controls that had been identified as important to safety in the Safety Analysis Report were limited to trained and certified personnel or were under the direct supervision of an individual with training and certification in the operation. Specifically, the licensee's training program:

1. Failed to adequately train and certify the rigger/spotter position involved in the important to safety downloading operation.

2. Failed to have adequate proficiency testing on the controls related to the load indicating device and downloading operations for the VCT operator position.

The team determined that this violation was more than minor because the licensee's failure to establish an adequate training program contributed to the misalignment incident on August 3, 2018. The team assessed and dispositioned this violation in accordance with Section 2.2.2 of the NRC Enforcement Policy. The team characterized the violation as a Severity Level IV violation. The NRC determined the issuance of a Notice is appropriate because the actions to restore compliance have not been fully developed and implemented, and the actions must be effective prior to beginning fuel handling activities. (VIO 07200041/2018-001-03, Failure to establish adequate training program)

The team identified that the simulator canister used for training and dry run demonstrations had a specified outer diameter that was less than that of the actual spent fuel storage canisters being downloaded into the vault. The simulator canister provided approximately 0.75 inch more clearance than the actual canisters loaded with spent fuel. This difference may be acceptable for the dry run activities; however, the difference was not noted in any of the licensee's training materials for rigger/spotters or the VCT operators. This represents a situation of negative training that may have contributed to the August 3, 2018, misalignment incident.

Conclusions

The important to safety lifting equipment and special lifting devices being used for dry cask storage operations met applicable regulatory requirements.

Personnel lacked the proper training, proficiency testing, and certifications to operate important to safety equipment identified in the HI-STORM UMAX SYSTEM FSAR, Revision 4, dated August 14, 2017. This was identified as a violation of 10 CFR 72.190 requirements.

3.1.3 Charter Items 2 and 4

<u>Inspection Scope</u>

"Evaluate the adequacy of the loading procedure(s) with respect to verification of the movement, centering, lowering, and positioning the canister within the ISFSI vault and procedure adherence. Interviews with personnel involved in the ISFSI loading operations should be conducted to evaluate licensee and contractor communications between crane/VCT operators, rigging and spotting staff, cask loading supervisors, radiation protection staff, and licensee oversight personnel. Evaluate the adequacy of pre-job briefings that may have taken place prior to fuel loading operations."

"Based on the review of the procedures and interviews of personnel involved with loading operations, evaluate the adequacy of procedure adherence."

The Special Inspection team reviewed Holtec Procedure HPP-2464-400, "Multi-Purpose Canister Transfer Operations at SONGS," Revision 15; Holtec Procedure HPP-2464-600, "Responding to Abnormal Conditions," Revision 6; SONGS Procedure SO123-0-A7, "Notification and Reporting of Significant Events," Revision 46; and other applicable procedures related to the August 3, 2018, misalignment incident. The team reviewed the pre-job briefing in use by the CLSs. The team discussed ISFSI communications during downloading operations with the licensee and contractor staff.

<u>Observations and Findings</u>

Violation of 10 CFR 72.150, Procedures

The VCT is not equipped with a load-cell to provide the weight of the canister. A hydraulic pressure indication for the lift beam could be used to provide a qualitative means for determining if the slings are not supporting the canister's weight. This pressure indication is displayed on the VCT HMI control panel.

The team identified examples of a violation of 10 CFR 72.150, "Instructions, Procedures, and Drawings." Holtec Procedure HPP-2464-400 provided direction and guidance for verifying canister movement, canister centering operations, and for lowering the canister into the vault. Many steps in the procedure provided direction without quantitative or qualitative means to verify that important to safety steps had been achieved, including detection of a loss-of-load condition and final verification that the canister had been fully downloaded into the vault. For example, step 7.6.12 instructed the VCT operator to continue to raise the VCT lift beam slowly until the full weight of the canister is on the VCT.

However, there is no quantitative direct measurement for the VCT operator to determine when the "full weight" of the canister is indicated on the VCT HMI control panel. The procedure contained a note that the load on the VCT HMI screen may be used to determine if downloader slings had become slack. However the procedure did not direct the VCT operator to monitor the HMI control panel nor provide a qualitative or quantitative value that would notify the VCT operator that the canister had become misaligned and that the VCT was no longer bearing the load of the canister.

Holtec Procedure HPP-2464-400, step 7.6.23, states, if at any time the download slings become slack prior to the canister being in the full down position then immediately stop lowering the canister. During downloading operations there was only one position who could determine whether or not the slings had gone slack. That position was the rigger/spotter who is responsible to monitor the movement of the canister during downloading operations from the elevated JLG basket. The rigger/spotter was observing the slings during the August 3, 2018, downloading evolution. However, the rigger/spotter was only observing the slings for "slack" at the top of the transfer cask.

The procedure did not provide adequate direction to the rigger/spotter to observe the slings near the base of the VCT, which had become slack and were bundling up on the ground. Additionally, the procedure did not provide direction for the rigger/spotter to monitor the height of the canister in relation to the height of the lift beam.

Title 10 CFR 72.150, requires, in part, that the licensee prescribe activities affecting quality by documented instructions or procedures of a type appropriate to the circumstances and must include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

Contrary to the above, from January 30 to August 3, 2018, the licensee failed to prescribe activities affecting quality by documented instructions or procedures of a type appropriate to the circumstances and include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Specifically:

1. Procedure HPP-2464-400, "Multi-Purpose Canister Transfer at SONGS," Revision 15, step 7.6.23, failed to provide qualitative and quantitative directions for the VCT operator to monitor control panel indications that would identify a canister had become misaligned during downloading operation.

2. Procedure HPP-2464-400, "Multi-Purpose Canister Transfer at SONGS," Revision 15, step 7.6.23, failed to include adequate instructions for the rigger/spotter to monitor the downloading slings for a slack condition.

The team determined that this violation was more than minor because the licensee's failure to prescribe adequate procedures contributed to the August 3, 2018, misalignment incident. The team assessed and dispositioned this violation in accordance with Section 2.2.2 of the NRC Enforcement Policy. The team characterized the violation as a Severity Level IV violation. The NRC determined the issuance of a Notice is appropriate because the actions to restore compliance have not been fully developed and implemented, and the actions must be effective prior to beginning fuel handling activities. (VIO 07200041/2018-001-04, Failure to provide adequate instructions of procedures)

Communications

During downloading on August 3, 2018, radiation protection staff directed the CLS and licensee oversight personnel to relocate to a low dose area off of the ISFSI pad. The low dose waiting area was located approximately 150 feet away from the ISFSI operations on the heavy haul path that is approximately 8 feet lower in elevation. From the low dose area, neither the contractor nor licensee oversight staff could observe the

downloading activities. The NRC determined that the removal of oversight staff in an effort to minimize radiation dose without other compensatory measures resulted in inadequate supervisory oversight of important to safety lifting operations.

The communication protocols used by the CLS, VCT operator, and the rigger/spotter was reviewed by the team. The CLS was in direct communications via radio and headsets with the VCT operator and rigger/spotter. The radios provided adequate communication in the noisy environment of the VCT. Communication between the CLS, VCT operator, and the rigger/spotter during the downloading operation was informal. The CLS did not request a reading of the HMI control panel to determine hydraulic pressure and repeat-backs of the location of canister during the downloading process were misunderstood.

Radiation Protection staff were not provided headsets for communications. Radiation Protection staff were able to communicate concerns directly with the CLS, who could communicate radiological concerns to workers, if necessary.

The licensee's oversight personnel were not provided headsets during downloading operations. The licensee did not provide direct oversight of downloading operations. During the August 3, 2018, misalignment incident, neither licensee oversight nor contractor supervision were in a position to directly monitor the downloading operations or the actual condition of the canister.

<u>Conclusions</u>

Dry cask storage procedures did not provide adequate directions for how to determine the downloader slings were slack. The downloading procedure did not include qualitative or quantitative means for determining when a canister had become misaligned. These procedure inadequacies were identified as examples of a violation of 10 CFR 72.150 requirements.

No licensee or contractor oversight personnel were in direct visual observations of the important to safety activities during downloading operations on August 3, 2018. All personnel except the rigger/spotter and VCT operator left the ISFSI pad during downloading operations. Licensee oversight was not a part of the communications between the CLS, the rigger/spotter, and VCT operator during canister downloading operations. Without adequate communications and visual observation, the licensee and the contractor were unable to verify that important to safety dry cask storage activities were adequately performed.

3.1.4 Charter Items 3 and 8

<u>Inspection Scope</u>

"Review and evaluate the licensee's immediate corrective actions taken after the incident for adequacy and notifications to the NRC and safety assessments performed immediately following the incident. Review the licensee's inspection documentation

and/or analysis to determine whether the vault's divider shell experienced any damage that would inhibit the component from performing its designed safety function."

"Investigate the licensee's procedures for reportability to the NRC and determine if the licensee made the correct decision regarding notifications made to the NRC for this incident."

The Special Inspection team reviewed the licensee's initial assessment of the incident through presentations and discussions provided by the licensee. The team reviewed all condition reports and entries made into the licensee's and dry cask storage vendor's corrective action programs regarding the canister misalignment incident, and the condition of the divider shell and canister 29. The team reviewed the notification requirements of 10 CFR 72.75 against the conditions experienced during the August 3, 2018, misalignment incident and reviewed licensee Procedure SO123-0-A7, "Notification and Reporting of Significant Events," Revision 46.

Observations and Findings

Divider Shell Assessment

The licensee immediately stopped all dry cask storage operations following the misalignment incident of August 3, 2018, pending a root cause evaluation to be performed by their dry cask storage vendor, Holtec International. The licensee initiated an apparent cause evaluation to determine if problems in its organization may have contributed to the misalignment incident.

The misalignment incident was entered into the corrective action program by Holtec as FCR 2464-1189. The Holtec FCR was initiated to investigate the August 3, 2018, incident as a human performance issue. This FCR prompted the licensee to initiate Action Request 0818-76588. This action request included an assessment of the condition of the divider shell and canister.

Action Request 0818-76588 described the removal of paint/coating from the divider shell. The action request concluded that the incidental transfer of divider shell coating to the canister shell did not affect the canister's design functions of confinement, shielding, structural, thermal, and criticality. Future actions to address coating presence will be included in the licensee's ISFSI aging management plan. The NRC team reviewed the licensee's assessment for the divider shell and concluded the component can perform its safety functions. Additionally, the licensee's plan to address future inspection of the divider shells in its aging management program was acceptable.

Apparent Violation 10 CFR 72.75, Reporting

The team identified an apparent violation of 10 CFR 72.75 for late notification of 24-hour reporting requirements involving important to safety equipment that was disabled or failed to function as designed when the equipment is required by license condition and no redundant equipment is available and operable to perform the required safety function.

On August 3, 2018, during downloading operations associated with canister 29 the licensee disabled the important to safety slings while downloading a canister (See

Section 2.1 and 2.2). The canister was placed in a potential load drop condition for approximately 45 minutes before the licensee was able to restore the load onto the important to safety slings, thereby restoring the redundant drop protection features.

After the incident, the licensee provided a courtesy notification to the NRC Region IV office at approximately 4 p.m. CDT on the afternoon of August 6, 2018. Section 10 CFR 72.75(d)(1), would have allowed for notification to be made to the NRC Operations Center as late as 0800 EDT on Monday, August 6, 2018. The courtesy notification made to the regional office did not satisfy the reporting requirements of 10 CFR 72.75. During the August 6, 2018, call, the NRC informed the licensee that a formal report to the NRC was likely required.

Notification of the NRC Operations Center did not occur until the licensee was prompted by the NRC team on September 14, 2018. The condition was reported to the NRC Headquarters Operations Center on September 14, 2018, at 1600 EDT (Event Notification 53605).

Title 10 CFR 72.75(d)(1) requires, in part, that each licensee shall notify the NRC within 24 hours after the discovery of any of the following events involving spent fuel in which important to safety equipment is disabled or fails to function as designed when: (i) the equipment is required by regulation, license condition, or certification of compliance to be available and operable to mitigate the consequences of an accident; and (ii) no redundant equipment was available and operable to perform the required safety function.

Contrary to the above, from August 6 to September 14, 2018, the licensee failed to notify the NRC after discovery of important to safety equipment being disabled and failing to function as designed when required by the Certificate of Compliance to provide redundant drop protection features to prevent and mitigate the consequences of a drop accident and no redundant equipment was available and operable to perform the required safety function.

The licensee's failure to make the required 24-hour notification to the NRC within the required timeframe was identified as an apparent violation of 10 CFR 72.75(d). (AV 07200041/2018-001-05, Failure to make 24-hour notification)

<u>Conclusions</u>

The licensee concluded that the incidental removal of divider shell coating during downloading operations did not affect the design functions for shielding, structural, and thermal safety functions. The NRC has reviewed the licensee's assessment for the divider shell and has concluded the component can perform its safety functions. Additionally, the licensee's plan to address future inspection of the divider shells in their aging management program is acceptable.

The licensee failed to make the required formal 24-hour NRC notification of the August 3, 2018, event where important to safety equipment was disabled when the equipment was required to mitigate the consequences of an accident and no redundant equipment was available to perform the safety function. This failure was identified as an apparent violation of 10 CFR 72.75(d) requirements.

3.1.5 Charter Item 6

Inspection Scope

"Review the licensee's root cause investigation results, to determine whether the review thoroughly identified all contributing factors and that final corrective actions will be adequate to prevent reoccurrence. Evaluate whether prior operational experience relating to complications or issues associated with canister downloading operations was identified and considered as part of the licensee's root cause investigation and corrective action development."

The Special Inspection team reviewed the causal evaluations that were performed for the August 3, 2018, misalignment incident. Specifically, the team reviewed Holtec International's Root Cause Analysis Report for the canister downloading incident and the licensee's Apparent Cause Evaluation to assess oversight effectiveness during the August 3, 2018, download of canister 29.

Observations and Findings:

Holtec International's Root Cause Evaluation

The licensee directed Holtec to perform a causal evaluation as a follow-up item in condition report action request 0818-76588 that the licensee initiated following the August 3, 2018, misalignment incident. The Holtec causal evaluation identified one root cause and five contributing causes:

- Root Cause: Holtec Management failed to implement appropriate program improvements or the necessary level of oversight commensurate with the complexity and risks associated with downloading operations.

- Contributing Cause 1: Inadequate content in procedures for recognizing special conditions.

- Contributing Cause 2: Design review process did not ensure that unintended consequences of design features were captured.

- Contributing Cause 3: Communication protocols with the chain of command established during canister movement were not well defined.

- Contributing Cause 4: Holtec had not established a continuous learning environment which promoted the use of internal and external operating experience.

- Contributing Cause 5: Holtec Training Program did not fully establish qualification or proficiency requirements for workers performing downloading operations.

Southern California Edison Company's Apparent Cause Evaluation

The licensee initiated an apparent cause evaluation (ACE) to determine how its organization may have contributed to allowing the August 3, 2018, loss-of-load incident to occur. The licensee's apparent causes were related to deficiencies in procedures, training, and in oversight of contractor activities.

- Apparent Cause 1: Management failed to establish a process to ensure that site dry cask storage procedures were technically accurate.

- Apparent Cause 2: Management failed to establish licensee and contractor training to support procedure implementation.

- Apparent Cause 3: Management failed to sufficiently detail contractor Oversight Specialist guidance.

- Contributing Cause 1: ISFSI project management was not routinely observing dry cask storage operations.

- Contributing Cause 2: ISFSI project management was not consistently initiating condition reports for dry cask storage operations that deviated from normal.

Both the licensee and Holtec causal evaluations reviewed many of the items identified by the NRC team. Those items being: procedure adequacy; training adequacy; adequacy of the corrective action program; oversight adequacy; and the inconsistent use of operational experience during routine dry cask storage operations.

The causal evaluations assessed the severity of the canister misalignment incident. The licensee determined that in the event of a canister drop accident from 25 feet into the vault, there was no risk of radioactive exposure to the public. A publicly available version of the licensee's drop analysis summary is available in ADAMS (ADAMS Accession No. ML18330A003). The NRC will continue to review the adequacy of the causal analyses, corrective actions, and potential consequences during a follow-up inspection which is planned to be performed before the resumption of fuel handling activities.

<u>Conclusions</u>

The apparent and root causes for the August 3, 2018, canister misalignment incident involved inadequate training, inadequate procedures, poor utilization of the corrective action program, and insufficient oversight.

3.1.6 Charter Item 7

<u>Inspection Scope</u>

"Review the licensee's planned actions that will address the point loading condition that was experienced by the affected canister. If applicable, review the licensee's analysis that demonstrated the canister will continue to perform as designed for continued storage OR review licensee's inspection plan to safely remove or lift the canister from

the vault to support inspection of the bottom of the canister to demonstrate the canister did not receive any damage that would inhibit the component from continuing to perform as designed."

Observations and Findings

The licensee performed an evaluation to demonstrate the canister continues to meet the design and performance requirements described in the FSAR. The Special Inspection team reviewed the licensee's initial assessment of the canister 29 condition after the misalignment incident.

The preliminary evaluation provided by the licensee stated that both the canister and vault were not expected to have any physical damage that would exceed the pre-defined limits used during receipt inspection and manufacturer acceptance testing. The NRC requested additional analysis to ensure that the canister meets design requirements. Additionally, the licensee is evaluating whether the canister will require increased surveillance frequency for the aging management program. The licensee had not completed the evaluation for NRC review prior to the NRC's inspection exit meeting. This charter item will be reviewed during a future NRC inspection.

Conclusions

The licensee has chosen to provide an analysis to demonstrate that the potential damage to canister 29 during the downloading would meet established acceptance criteria. The NRC determined that additional analysis was required for the NRC to ensure that the canister meets design requirements. This charter item will be reviewed during a future NRC inspection.

3.1.7 Charter Item 9

Inspection Scope

"As directed by regional management, observe resumption of fuel loading operations to verify that corrective actions were effective in addressing deficiencies that contributed to the incident. This should include evaluation of procedure and/or equipment enhancements; review or observation of training and briefings provided to riggers, crane operators, spotters and observers, supervisors and other personnel involved in fuel loading operations."

Observations and Findings

The licensee suspended all fuel handling activities following the August 3, 2018, misalignment incident. The NRC will review the licensee's revised procedures, training plans, equipment modifications, and performance testing (dry runs) of its dry cask storage operations in a future inspection to determine the effectiveness of corrective actions for the incident.

Conclusions

All associated corrective actions for the August 3, 2018, incident had not been completely finalized or implemented by the licensee. The NRC will review the licensee's

revised procedures, training plans, equipment modifications, and performance testing (dry runs) of its dry cask storage operations during a future inspection to determine the effectiveness of corrective actions for the incident.

3.1.8 Charter Item 10

Inspection Scope:

"Determine if the inspection should be elevated to an Augmented Inspection Team (AIT) inspection and promptly notify regional management of any recommendation to escalate the special inspection to an AIT."

As a daily action item, the NRC Special Inspection Team reviewed NRC Inspection Manual Chapter 0309, "Reactive Inspection Decision Basis for Reactors," Enclosure 2, to determine whether any of the facts or details uncovered during the course of the inspection met the deterministic criteria that would require the Special Inspection at SONGS to be elevated to an AIT.

Observations and Findings

The deterministic criteria for an event to be elevated to an AIT effort are delineated in Manual Chapter 0309. The Special Inspection Team did not identify any indication that the August 3, 2018, misalignment incident at SONGS led to a radiological release. Additionally, the incident did not involve the failure of the spent fuel canister, the release of radiological contamination, or external radiation levels that exceeded 10 rads/hr. Consequently, there was no need to elevate the inspection effort to an AIT. The team's daily re-evaluation was communicated to Regional management during the week of onsite inspection effort.

Conclusions

The NRC team did not identify any information that would have required the Special Inspection to be elevated to an AIT effort.

4 Exit Meeting Summary

On September 14, 2018, following the onsite portion of the inspection, the inspectors provided a debrief of the preliminary results to Mr. Tom Palmisano, former Vice President and Chief Nuclear Officer and other members of the licensee staff. The licensee acknowledged the issues presented by the NRC inspection team.

On November 1, 2018, the inspectors presented the final inspection results to Mr. Tom Palmisano, former Vice President and Chief Nuclear Officer and other members of the licensee staff. The licensee acknowledged the issues presented.

On November 8, 2018, the NRC performed a public webinar meeting to discuss the inspection team's preliminary results.

SUPPLEMENTAL INSPECTION INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee Personnel

A. Bates, Regulatory and Oversight Manager
M. Morgan, Regulatory and Oversight
L. Bosch, Plant Manager
G. Carter, Westinghouse Project Manager
P. Chaudnary, Vice President of Operations, Holtec
J. Manso, ISFSI Sr. Project Manager
T. Palmisano, former Vice President Decommissioning and Chief Nuclear Officer
J. Pugh, Project Engineer
K. Rod, General Manager Decommissioning Oversight
J. Smith, Project Manager, Holtec
M. Soler, Vice President Quality, Holtec

INSPECTION PROCEDURES USED

IP 93812 Special Inspection

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

072-00041/2018-001-01	VIO	Failure to identify and correct conditions adverse to quality (10 CFR 72.172)
072-00041/2018-001-02	AV	Failure to ensure redundant drop protection features were available (10 CFR 72.212)
072-00041/2018-001-03	VIO	Failure to assure that operations of important to safety equipment were limited to trained and certified personnel (10 CFR 72.190)
072-00041/2018-001-04	VIO	Failure to provide adequate instructions or procedures (10 CFR 72.150)
072-00041/2018-001-05	AV	Failure to make 24-hour notification (10 CFR 72.75)

Discussed

None

Closed

None

Attachment

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access and Management System
ADR	Alternative Dispute Resolution
AIT	Augmented Inspection Team
ANSI	American National Standards Institute
AV	Apparent Violation
ASME	American Society of Mechanical Engineers
CFR	*Code of Federal Regulations*
CLS	Cask Loading Supervisor
FCR	Field Condition Report
FSAR	Final Safety Analysis Report
HI-STORM UMAX	Holtec International Storage Module Underground Maximum Capacity
HMI	Human-Machine Interface
IP	Inspection Procedure
ISFSI	Independent Spent Fuel Storage Installation
JLG	Engine or Motor Powered Boom Lifting Device
NOV	Notice of Violation
NRC	U.S. Nuclear Regulatory Commission
MPC	multipurpose canister
PEC	Pre-decisional Enforcement Conference
RIC	Rigger-in-charge
RPT	Radiation Protection Technician
SL	Severity Level
SONGS	San Onofre Nuclear Generating Station
TS	Technical Specification
VCT	Vertical Cask Transporter
VIO	Violation
VVM	Vertical Ventilated Module or vault

INSPECTION CHARTER

TO EVALUATE THE NEAR-MISS LOAD DROP EVENT AT SAN ONOFRE NUCLEAR GENERATING STATION DATED AUGUST 17, 2018 (ML18229A203)

Enclosure 3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 EAST LAMAR BOULEVARD
ARLINGTON, TEXAS 76011-4511

August 17, 2018

MEMORANDUM TO: Eric J. Simpson, CHP, Health Physicist
Fuel Cycle and Decommissioning Branch
Division of Nuclear Materials Safety

W. Chris Smith, Reactor Inspector
Engineering Branch 1
Division of Reactor Safety

Marlone X. Davis, Transportation & Storage Safety Inspector
Inspections & Operations Branch
Division of Spent Fuel Management

THROUGH: Janine F. Katanic, PhD, CHP, Chief /RA/ LLH for
Fuel Cycle and Decommissioning Branch
Division of Nuclear Materials Safety

FROM: Troy W. Pruett, Director /RA/
Division of Nuclear Materials Safety

SUBJECT: INSPECTION CHARTER TO EVALUATE THE NEAR-MISS LOAD DROP EVENT AT SAN ONOFRE NUCLEAR GENERATING STATION

A special inspection has been chartered to review the licensee's follow-up investigation, causal evaluation, and planned corrective actions regarding the near-miss drop event involving a loaded spent fuel storage canister at the San Onofre Nuclear Generating Station (SONGS) Independent Spent Fuel Storage Installation (ISFSI) on Friday, August 3, 2018. (License Nos. NPF-10 and NPF-15, Docket Nos. 50-361, 50-362 and 72-41).

CONTACT: Janine F. Katanic, PhD, CHP, FCDB/DNMS
(817) 200-1151

BACKGROUND AND BASIS

On Friday, August 3, 2018, at approximately 1:30 pm (PST), SONGS was engaged in operations involving movement of a loaded spent fuel storage canister into its underground ISFSI storage vault (HI-STORM UMAX storage system). As the loaded spent fuel canister was being lowered into the storage vault using lifting and rigging equipment, the licensee's personnel failed to notice that the canister was misaligned and was not being properly lowered. The licensee continued to lower the rigging and lifting equipment until it believed that the canister had been fully lowered to the bottom of the storage vault. However, a radiation protection technician identified elevated radiation readings that were not consistent with a fully lowered canister. The licensee then identified that the loaded spent fuel canister was hung up on a metal flange near the top of the storage vault, preventing it from being lowered, and that the rigging and lifting equipment was slack and no longer bearing the load of the canister.

In this circumstance, with the important to safety (ITS) rigging and lifting equipment completely down in the lowest position, the ITS equipment was disabled from performing its designed safety function of holding and controlling the loaded canister from a potential canister drop condition. The licensee reported that the canister was resting on a metal flange within the storage vault. It was estimated that the canister could have experienced an approximately 17-18 foot drop into the storage vault if the canister had slipped off the metal flange or if the metal flange failed. This load drop accident is not a condition analyzed in the dry fuel storage system's Final Safety Analysis Report (FSAR).

In response to the discovery that the canister was not fully lowered, the licensee took immediate actions to restore control of the load to the rigging and lifting devices. The estimated time the canister was in an unanalyzed credible drop condition was approximately 45 minutes to 1 hour in duration. The licensee regained control of the load, repositioned the canister, and lowered the canister into the storage vault. The licensee halted all dry fuel storage movement operations in order to fully investigate the incident and develop corrective actions to prevent a recurrence. In addition, the licensee has shared the operational experience with another site with a similar dry fuel storage system.

Region IV became aware of the SONGS "near-miss" incident on Monday, August 6, 2018, when the licensee provided a courtesy notification and described it as a "near-miss" or "near-hit" event. The reporting requirements of the incident are still being evaluated by the Region and discussed with the licensee.

On August 7 and 16, 2018, Region IV and NMSS representatives participated in conference calls with licensee representatives in order to gather additional facts regarding the circumstances of the incident and the licensee's investigation. Region IV is evaluating the information provided by the licensee and is coordinating with the Division of Spent Fuel Management, NMSS.

The NRC is chartering this special inspection pursuant to Management Directive 8.3, "NRC Incident Investigation Program," and NRC Inspection Manual Chapter 0309, "Reactive Inspection Decision Basis for Reactors."

The purpose of the inspection is to investigate the occurrence; interview personnel; observe equipment; and review relevant documentation, including the results of the licensee's investigation and causal analysis, and development and implementation of actions to prevent

recurrence. The licensee has committed to not resume fuel loading operations until after this special inspection and associated reviews are complete. Once the licensee has confirmed its plans to resume fuel loading operations, inspectors will also observe the loading operations to ensure that the corrective actions are adequate. These observations may be conducted as part of this special inspection or as an independent inspection activity, as directed by regional management.

SCOPE

The inspection should seek to address the following items at a minimum:

1. Identify and review all pertinent records, documents, and procedures related to the licensee's downloading operations at the ISFSI pad including but not limited to: worker training and qualifications; rigging equipment qualification, testing, and preventative maintenance; and lifting equipment qualification, testing, and preventative maintenance. Evaluate the adequacy of the above noted procedures, worker training and equipment testing and preparation.

2. Evaluate the adequacy of the loading procedure(s) with respect to verification of MPC movement, centering the MPC over the ISFSI vault, lowering the MPC, and positioning the MPC within the ISFSI vault. Interviews with personnel involved in the ISFSI loading operations should be conducted to evaluate licensee and contractor communications between crane/VCT operators, rigging and spotting staff, cask loading supervisors, radiation protection staff, and licensee oversight personnel. Evaluate the adequacy of pre-job briefings that may have taken place prior to fuel loading operations.

3. Review and evaluate the licensee's immediate corrective actions taken after the event for adequacy of notifications to the licensee and safety assessments performed immediately following the event. Review the licensee's inspection documentation and/or analysis to determine whether the vault's divider shell experienced any damage that would inhibit the component from performing its designed safety function.

4. Based on the review of procedures and interviews of personnel involved with loading operations, evaluate the adequacy of procedure adherence.

5. Interview personnel associated with the event to develop a timeline to ensure the licensee's investigation contained all necessary information to identify all contributing factors and develop adequate corrective actions.

6. Review the licensee's root cause investigation results, to determine whether the review thoroughly identified all contributing factors and that final corrective actions will be adequate to prevent reoccurrence. Evaluate whether prior operational experience relating to complications or issues associated with canister downloading operations was identified and considered as part of the licensee's root cause investigation and corrective action development.

7. Review the licensee's planned actions that will address the point loading condition that was experienced by the affected canister. If applicable, review the licensee's analysis that demonstrated the canister will continue to perform as designed for continued storage OR review licensee's inspection plan to safely remove or lift the canister from the vault to support inspection of the bottom of the canister to demonstrate the canister did not

receive any damage that would inhibit the component from continuing to perform as designed.

8. Investigate the licensee's procedures for reportability to the NRC and determine if the licensee made the correct decision regarding notifications made to the NRC for this event.

9. As directed by regional management, observe resumption of fuel loading operations to verify that corrective actions were effective in addressing deficiencies that contributed to the event. This should include evaluation of procedure and/or equipment enhancements; review or observation of training and briefings provided to riggers, crane operators, spotters and observers, supervisors and other personnel involved in fuel loading operations.

10. Determine if the inspection should be elevated to an AIT and promptly notify regional management of any recommendation to escalate the special inspection to an AIT.

GUIDANCE

The NRC is chartering this special inspection pursuant to Management Directive 8.3, "NRC Incident Investigation Program," and NRC Manual Chapter 0309, "Reactive Inspection Decision Basis for Reactors." The Manual Chapter and Management Directive identify Inspection Procedure 93812, "Special Inspection," for specific use in reviewing events. Planned Dates of Inspection are September 10-14, 2018.

This inspection should emphasize fact-finding in its review of the circumstances surrounding the near-miss canister drop event. Safety concerns identified that are not directly related to near-miss drop event should be reported to NRC management for appropriate action.

Daily briefings with NRC management should occur to discuss the team's progress and preliminary observations.

In accordance with Manual Chapter 0610, a report documenting the results of the inspection should be issued within 30-45 days of the completion of the inspection.

This Charter may be modified should NRC inspectors find significant new information that warrants review. Should you have any questions concerning this charter, please contact Janine F. Katanic at 817-200-1151.

ENVIRONMENTAL REPORT

on

The HI-STORE CIS FACILITY

by

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Summary of Revisions:

Revision 0: Initial Issue

Revision 1: Revised to include responses to NRC RSIs. All above changes and editorial changes are shown by revision bars in the right margin.

Revision 2: Added appendices F and G for "data call" references.

Revision 3: Revised to include responses to NRC RAIs. All changes and editorial changes are shown by revision bars in the right margin.

Revision 4: Revised Section 4.11 to include annual and total volume estimates for low-level radioactive wastes and nonhazardous solid wastes.

Revision 5: Revised to include responses to NRC Round 1 Part 4 RAIs. All changes and editorial changes are shown by revision bars in the right margin

Revision 6: Incorporated supplementary Cultural Resource Surveys, which are attached in Appendix C. Revised figure 3.1.2 with current layout.

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CHAPTER 7: MONITORING

CHAPTER 8: SUMMARY OF ENVIRONMENTAL CONSEQUENCES

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ACRONYMS AND ABBREVIATIONS

°F	degrees Fahrenheit
AADT	annual average daily traffic
ACEC	Area of Critical Environmental Concern
ACHP	Advisory Council on Historic Preservation
ALARA	as low as reasonably achievable
amsl	above mean sea level
APE	Area of Potential Effects
ARMS	Archaeological Records Management Section
BISON	Biota Information System of New Mexico
BLM	Bureau of Land Management
BLS	Bureau of Labor Statistics
BMP	best management practices
BNSF	Burlington Northern-Santa Fe
CAA	Clean Air Act
CEC	Cavity Enclosure Containers
CEDE	committed effective dose equivalent
CESQG	Conditionally Exempt Small Quantity Generator
CFO	Carlsbad Field Office
CFR	Code of Federal Regulations
CISF	Consolidated Interim Storage Facility
CLSM	Controlled Low Strength Material
CO	carbon monoxide
CO2e	carbon dioxide equivalent
CoC	Certificate of Compliance
CWA	Clean Water Act
D&D	decontamination and decommissioning
dB	decibel units
dBA	A-weighted decibels
DE	dose equivalent
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
EDE	effective dose equivalent
EIS	Environmental Impact Statement
ELEA	Eddy-Lea Energy Alliance
EMS	Emergency Medical Services
EMT	Emergency Medical Technician

EPA	U.S. Environmental Protection Agency
ER	Environmental Report
FEIS	Final Environmental Impact Statement
FEMA	Federal Emergency Management Agency
FEP/DEP	Fluorine Extraction Process and Depleted Uranium De-conversion Plant
FLMPA	Federal Land Policy and Management Act
FR	Federal Register
FSAR	Final Safety Analysis Report
GCR	Geological Characterization Report
GHG	Greenhouse Gas
GNEP	Global Nuclear Energy Partnership
GPS	Global Positioning System
HI-STORM UMAX	Holtec International Storage Module Underground MAXimum Capacity
HLW	High-Level Waste
Holtec	Holtec International
HPD	Historic Preservation Division
HUD	Department of Housing and Urban Development
ICRP	International Commission on Radiation Protection
IIFP	International Isotopes Fluorine Production
IO	Isolated Occurrences
ISCORS	Interagency Steering Committee on Radiation Standards
ISFSI	Independent Spent Fuel Storage Installation
LLRW	Low-Level Radioactive Waste
MDC	Minimum Detectable Concentration
MEI	maximally exposed individual
MN	Midessa and Wink fine sandy loams
MOA	memorandum of agreement
MPC	Multi-Purpose Canister
mph	miles per hour
mrem	millirem
MRS	Monitored Retrievable Storage Installation
MTU	metric tons of uranium
MU	Mixed alluvial land
MW	Mobeetie-Potter association
NAAQS	National Ambient Air Quality Standards
NAC	NAC International
NBS	National Bureau of Standards Handbook

NEF	National Enrichment Facility
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
NMAAQS	New Mexico Ambient Air Quality Standards
NMCRIS	New Mexico Cultural Resources Information System
NMDOT	New Mexico Department of Transportation
NMED	New Mexico Environmental Department
NMHPD	New Mexico Historic Preservation Division
NMWQB	New Mexico Water Quality Bureau
NMRPTC	New Mexico Rare Plant Technical Council
NOI	Notice of Intent
NOx	oxide of nitrogen
NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission
NRCS	Natural Resources Conservation Service
NRHP	National Register of Historic Places
NUREG	U.S. Nuclear Regulatory Commission Regulation
NWS	National Weather Service
NWPA	Nuclear Waste Policy Act
O_3	ozone
OCD	Oil Conservation Division
OSHA	Occupational Safety and Health Administration
OSL	optically stimulated luminescence
Pb	lead
PFS	Private Fuel Storage
PGA	Peak Horizontal Ground Acceleration
PM	particulate matter
PM10	particulate matter less than or equal to 10 microns
PM2.5	particulate matter less than or equal to 2.5 microns
PPH	pounds per hour
PRA	probabilistic risk assessment
QA	quality assurance
QC	quality control
RBE	relative biological effect
RCRA	Resource Conservation and Recovery Act
REMP	Radiological Environmental Monitoring Program
ROI	region of influence
ROW	rights-of-way
RPA	Registered Professional Archaeologist

SAR	Safety Analysis Report
SDWA	Safe Drinking Water Act
SE	Simona fine sandy loam
SES	Self-Hardening Engineering Subgrade
SFP	Support Foundation Pad
SHPO	State Historic Preservation Officer
Site	Proposed CISF Site
SNF	Spent Nuclear Fuel
SO2	sulfur dioxide
SONGS	San Onofre Nuclear Generating Station
SPCC	Spill Prevention, Control, and Countermeasures Plan
SR	Simona-Upton association
SRI	Statistical Research, Inc.
SWAT	Special Weapons and Tactics
SWPP	Stormwater Pollution Prevention Plan
T&E	threatened and endangered
TEDE	total effective dose equivalent
TLDs	thermoluminescent dosimeters
TNMR	Texas-New Mexico Railroad
TPY	tons per year
TPWD	Texas Parks and Wildlife Department
TRU	transuranic
TSP	total suspended particulates
U.S.	United States
USACE	U.S. Army Corps of Engineers
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
USTs	Underground Storage Tanks
UWB	Underground Water Basin
VCT	Vertical Cask Transporter
VOCs	volatile organic compounds
VRM	Visual Resource Management
VVM	Vertical Ventilated Modules
WCS	Waste Control Specialist
WIPP	Waste Isolation Pilot Plant
WRCC	Western Regional Climate Center

CONVERSION CHART

TO CONVERT FROM U.S. CUSTOMARY INTO METRIC			TO CONVERT FROM METRIC INTO U.S. CUSTOMARY		
If you know	**Multiply by**	**To get**	**If you know**	**Multiply by**	**To get**
		Length			
inches	2.540	centimeters	centimeters	0.3937	inches
feet	30.48	centimeters	centimeters	0.03281	feet
feet	0.3048	meters	meters	3.281	feet
yards	0.9144	meters	meters	1.094	yards
miles	1.609	kilometers	kilometers	0.6214	miles
		Area			
square inches	6.452	square centimeters	square centimeters	0.1550	square inches
square feet	0.09290	square meters	square meters	10.76	square feet
square yards	0.8361	square meters	square meters	1.196	square yards
acres	0.4047	hectares	hectares	2.471	acres
square miles	2.590	square kilometers	square kilometers	0.3861	square miles
		Volume			
fluid ounces	29.57	milliliters	milliliters	0.03381	fluid ounces
gallons	3.785	liters	liters	0.2642	gallons
cubic feet	0.02832	cubic meters	cubic meters	35.31	cubic feet
cubic yards	0.7646	cubic meters	cubic meters	1.308	cubic yards
		Weight			
ounces	28.35	grams	grams	0.03527	ounces
pounds	0.4536	kilograms	kilograms	2.205	pounds
short tons	0.9072	metric tons	metric tons	1.102	short tons
		Temperature			
Fahrenheit (°F)	subtract 32, then multiply by 5/9	Celsius (°C)	Celsius (°C)	multiply by 9/5, then add 32	Fahrenheit (°F)
Kelvin (K)	subtract 273.15	Celsius (°C)	Celsius (°C)	add 273.15	Kelvin (K)

Note: 1 sievert = 100 rem

CHAPTER 1: INTRODUCTION

1.0 INTRODUCTION

Holtec International (Holtec) has prepared a license application for a Consolidated Interim Storage (CIS) Facility for approval by the United States (U.S.) Nuclear Regulatory Commission (NRC) pursuant to the requirements specified in Title 10 of the Code of Federal Regulations (CFR), Part 72, *Licensing Requirements for the Independent Storage of Spent Nuclear Fuel, High-Level Radioactive Waste, and Reactor-Related Greater Than Class C Waste*. The proposed site (hereafter, "Site") for the CIS Facility is located in southeastern New Mexico in Lea County, 32 miles east of Carlsbad, New Mexico, and 34 miles west of Hobbs, New Mexico (Figure 1.0.1).

Holtec has prepared this Environmental Report (ER) to evaluate the potential radiological and non-radiological impacts associated with the construction and operation of the CIS Facility for Spent Nuclear Fuel (SNF) and Reactor-Related Greater than Class C Low-Level Radioactive Waste (LLRW) (hereafter, referred to collectively as "SNF") in Lea County, New Mexico. Holtec is proposing to construct and operate Phase 1 of the CIS Facility within an approximately 1,040 acre parcel. Holtec is currently requesting authorization to possess and store 500 canisters of SNF containing 8,680 metric tons of uranium (MTUs), which includes spent uranium-based fuel from commercial nuclear reactors as well as a small quantity of spent mixed-oxide fuel. If the requested license is issued by the NRC, Holtec anticipates subsequently requesting an amendment to the license to request authorization to possess and store SNF containing additional 500 canisters for each of 19 subsequent expansion phases to be completed over the course of 20 years. Ultimately, Holtec anticipates that approximately 10,000 canisters of SNF would be stored at the CIS Facility upon completion of 20 phases. In total, this ER analyzes the environmental impacts of possession and storage of SNF containing 100,000 MTUs (each canister type contains different design basis MTUs).

This ER was prepared to support a License Application for review and approval by the NRC pursuant to the requirements specified in 10 CFR Part 72.34 and in 10 CFR Part 51.61, *Environmental Report—Independent Spent Fuel Storage Installation (ISFSI) or Monitored Retrievable Storage Installation (MRS) license.* Holtec prepared this ER consistent with the guidance provided in two regulatory documents:

Regulatory Guide 3.50, *Standard Format and Content for A Specific License Application for an Independent Spent Fuel Storage Installation or Monitored Retrievable Storage Facility* (NRC 2014a);

U.S. Nuclear Regulatory Commission Regulation (NUREG)-1748, *Environmental Review Guidance for Licensing Actions Associated with NMSS Programs* (NRC 2003).

Holtec anticipates that the NRC would issue the Final Environmental Impact Statement (FEIS) and License in 2019. Phase 1 construction would begin after issuance of the license and after Holtec successfully enters into a contract for storage with the U.S. Department of Energy (DOE) or utility. Construction on Phase 1 is expected to begin in the first quarter of 2020 and be complete within 1.5 years. After preoperational testing, Phase 1 of the CIS Facility is expected to be operational in early 2022. In this ER, Holtec has assumed that SNF could be stored at the CIS Facility for approximately 120 years (40 years for initial licensing plus 80 years for life extensions). That storage period could be reduced if a final geologic repository is licensed and

operating in accordance with the Nuclear Waste Policy Act (NWPA) of 1982, as amended (Holtec 2016a).

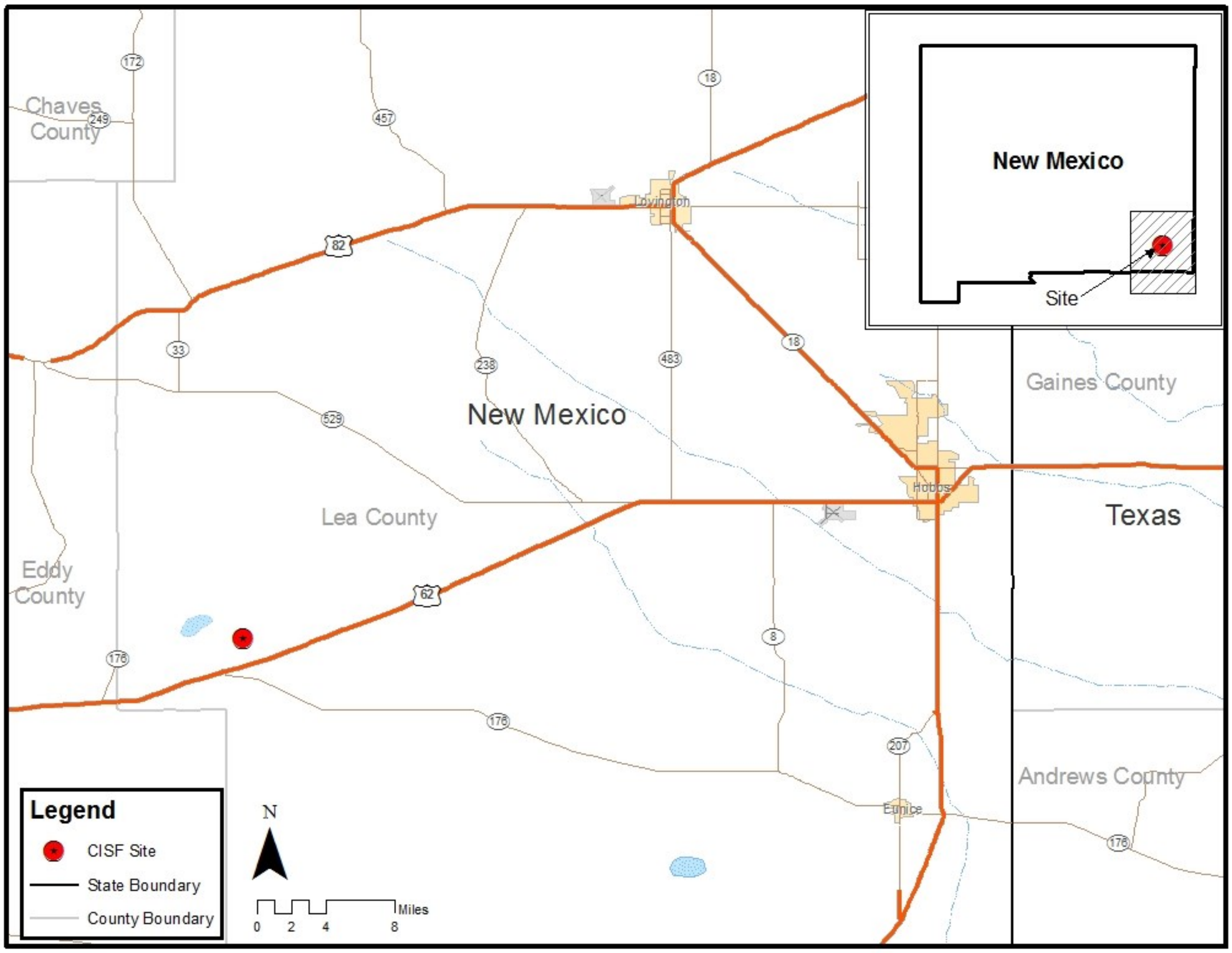

Figure 1.0.1: LOCATION OF PROPOSED CIS FACILITY

1.1 HISTORY AND BACKGROUND

The U.S. Congress enacted the NWPA of 1982 assigning DOE the task of developing a geologic repository for the disposal of SNF generated by commercial nuclear power plants located throughout the U.S. In 1987, Congress amended the NWPA to streamline and focus SNF management on developing the geologic repository at Yucca Mountain, located in Nye County, Nevada. Pursuant to the NWPA, DOE was responsible for obtaining required licenses for Yucca Mountain with operations to begin on January 31, 1998.

On July 23, 2002, President Bush approved Congressional legislation designating Yucca Mountain as the final geologic repository intended for the disposal of commercial SNF and high-level waste (HLW) generated by the Federal government. DOE submitted a license application to the NRC for authorization to construct and operate Yucca Mountain. The NRC reviewed the license application and issued a series of Safety Evaluation Reports addressing the long-term environmental performance of Yucca Mountain. However, much uncertainty remains as to whether or not the facility will open and begin accepting commercial SNF or HLW for disposal. In January 2010, President Obama established the Blue Ribbon Commission on America's Nuclear Future. The Commission was directed by the Secretary of Energy to conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle and to recommend a new strategy. On January 26, 2012, the Blue Ribbon Commission issued a final report consisting of eight key recommendations. Of paramount importance to this licensing action was the Blue Ribbon Commission's recommendation to adopt a new consent-based approach to siting future nuclear waste management facilities in order to initiate prompt efforts to develop one or more consolidated storage facilities (BRC 2012, Chapter 6).

Consistent with the Blue Ribbon Commission's recommendation, on December 23, 2015, DOE announced that it would implement a consent-based siting process to establish an integrated waste management system to transport, store, and dispose of SNF and HLW. In a consent-based siting approach, DOE would work with communities, tribal governments and states across the country that express interest in hosting any of the facilities identified as part of an integrated waste management system. As part of this process, DOE solicited public comments and hosted a series of public meetings to engage communities and discuss the development of a consent-based approach to managing SNF and HLW (80 Federal Register [FR] 79872).

Although the consent-based approach applies to Federal proposals, that approach is indirectly applicable to private proposals such as Holtec's. For example, it is possible that DOE would evaluate proposals such as Holtec's for consistency with the Federal consent-based approach. To that end, Holtec's proposal has been vetted and discussed publicly both at the local and state-level, as discussed below and in Section 2.3 (Site Selection Process).

Development of Holtec's CIS Facility has support from the state, regional, and local communities located in southeastern New Mexico. In an April 10, 2015 letter, New Mexico Governor Martinez wrote to Energy Secretary Ernest Moniz, urging the administration to look to southeastern New Mexico to store the SNF. "Time and time again, the citizens of southeastern New Mexico have impressed me with their hard work ethic and willingness to tackle national problems that many others consider to be unsolvable," Martinez wrote. "In one of the most remote areas of the state, they have had the ingenuity and fortitude to carve out a niche in the nuclear industry to broaden

their economic base. They understand the benefits not only to their local economy, but also to our country" (Martinez 2015).

In February 2016, the New Mexico Senate Conservation Committee approved a nonbinding measure to signal support for the development of the CIS Facility. Although the measure does not hold any legal weight, supporters of the CIS Facility view it as an endorsement from the State Legislature that would help in what is likely to be a competitive process as the Federal government weighs proposals for storing SNF (ALBQ Journal 2016).

In April 2016, Holtec and the Eddy-Lea Energy Alliance[1] (ELEA) announced the signing of a memorandum of agreement (MOA) covering the design, licensing, construction and operation of the CIS Facility. Among other things, that MOA provides the means by which Holtec could purchase the Site proposed for the CIS Facility (ELEA 2016). On July 19, 2016, the New Mexico Board of Finance approved the sale of the Site to Holtec (NMBF 2016).

With regard to previous efforts to license a private storage facility for SNF, in December 2001, the NRC previously prepared the *Final Environmental Impact Statement (EIS) for the Construction and Operation of an Independent Spent Fuel Storage Installation on the Reservation of the Skull Valley Band of the Goshute Indians and Related Transportation Facility in Tooele County, Utah*, NUREG-1714 (NRC 2001). The subject of that EIS, a facility referred to as the "Private Fuel Storage" (PFS) facility," was designed and licensed to store up to 40,000 MTUs of SNF in sealed metal casks (approximately 4,000 storage casks) for a term of 20 years. The PFS facility was never licensed or constructed.

More recently, the NRC directed staff to develop a waste confidence decision and promulgated the Continued Storage Rule to be supported by an environmental impact statement (SRM-COMSECY-12-0016) (NRC 2012a). As such, the NRC completed a *Generic Environmental Impact Statement for Continued Storage of Spent Nuclear Fuel* (NUREG-2157) (NRC 2014b) that addressed the impacts attributable to continued storage of SNF. The report was needed by the NRC to fulfill its responsibilities under the National Environmental Policy Act (NEPA). The environmental impacts evaluated in NUREG-2157 include those related to short-term (60 years), long-term (an additional 100 years), and indefinite storage of SNF at existing commercial nuclear power plants, as well as at an "away-from-reactor" storage facility.

In developing NUREG-2157, NRC referred to the previous environmental analyses that supported issuance of the FEIS for the PFS facility in Tooele, Utah. The NRC concluded that implementation of the Preferred Alternative to issue a license to the PFS authorizing construction and operation of an ISFSI in Tooele County, Utah would generally be small (NRC 2014b, Table ES-4).

This ER constitutes a site-specific analysis of the proposed CIS Facility at the southeastern New Mexico Site in Lea County. This ER incorporates relevant information and analyses from NUREG-2157 as appropriate, for purposes of completeness. For example, for most resources analyzed in Chapter 4 of this ER, there is a high-level comparison of the site-specific impact conclusions presented in this ER to the generic impact conclusions contained in NUREG-2157.

[1] The Eddy-Lea Energy Alliance is a limited liability company owned by the cities of Carlsbad and Hobbs, and Eddy County and Lea County.

1.2 PURPOSE AND NEED FOR THE PROPOSED ACTION

DOE has not yet developed a permanent geologic repository to allow for the disposal of commercial SNF at Yucca Mountain in Nye County, Nevada, as required under the NWPA. DOE was required to open the repository and begin accepting SNF for disposal at Yucca Mountain on January 31, 1998. However, the earliest estimated time by which a permanent geologic repository could be licensed and operational is 2048 (DOE 2013, pg. 7). The only alternatives currently available to the commercial nuclear power utilities (whether currently operational or decommissioned and non-operational are to either continue to store SNF in onsite ISFSIs or at an "away-from-reactor" storage facility. However, there are currently no licensed away-from-reactor storage facilities for accepting SNF from commercial reactors.

At the time this ER was prepared, three nuclear power plants have been shut down and are in the process of being decommissioned and nine nuclear power plants across the U.S. have been decommissioned (hereafter referred to as the "decommissioned shutdown sites") to levels that would allow for unrestricted release of the site in accordance with the NRC's License Termination Rule (10 CFR 20, Subpart E). Even though in some cases the nuclear power plants, including the SNF pools, have been dismantled and decommissioned, the SNF remains and continues to be stored in onsite ISFSIs. Many policymakers and stakeholders in the communities that host shutdown reactors want to have the SNF removed to complete decommissioning of the site and to allow for more beneficial uses of the land.

While decommissioning activities have been completed at nine locations across the U.S. (except for removing the SNF from dry cask storage), other financial pressures are expected to cause utilities to shut down and begin decommissioning other commercial nuclear reactors. A CIS Facility is needed to ensure that the SNF at these commercial reactor sites can be safely removed so that the remaining lands can be returned to Greenfield status. This point is further underscored with the announcement by other electric utilities of their plans to shut down and decommission additional commercial reactors located throughout the U.S.

The nuclear power utilities continue to remain responsible for the surveillance, maintenance, emergency preparedness, and physical security of the SNF stored at their ISFSI (unless otherwise exempted by the NRC). These activities are estimated to cost each of the utilities at the decommissioned shutdown sites an estimated $4.5-8 million per year (BRC 2012, Section 5.2.1). Developing a CIS Facility in Lea County, New Mexico, in the most timely manner possible, serves a national strategic need by providing for an orderly transfer of SNF from the decommissioned shutdown sites to a safer and more secure centralized storage location (NRC 2003). In addition to serving the needs of the decommissioned shutdown sites, a CIS Facility also serves the needs of the existing operating commercial nuclear reactors in the U.S., until a permanent repository becomes available. A CIS Facility alleviates the need to construct new or expanded ISFSIs at these operating sites.

There are only two reasonable alternatives that would meet the purpose and need described in this section; (1) the No Action Alternative, described in Section 2.1 and (2) the Proposed Action, described in Section 2.2. Chapter 4 discusses the impacts associated with the two reasonable alternatives. Section 2.4 discusses alternatives that were considered but eliminated from detailed study, and explains why those alternatives were not reasonable.

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1.3 THE PROPOSED ACTION

Pursuant to the requirements specified in Title 10 of CFR Part 72, Holtec is requesting a license from the NRC for authorization to construct and operate a CIS Facility in Lea County, New Mexico, 32 miles east of Carlsbad, New Mexico, and 34 miles west of Hobbs, New Mexico (Figure 1.3.1). Accounting for the Protected Area (i.e., the area within the security fence containing the ISFSI Pads and the Cask Transfer Building), Phase 1 construction would disturb approximately 119.4 acres (177,250 yd^3 excavated soil). Of this disturbance, approximately 6.2 acres (40,000 yd^3 excavated soil) would be associated with constructing the Site access road and relocating the existing road that currently runs through the Site; 39.4 acres (31,500 yd^3 excavated soil) would be associated with constructing a railroad spur; and 1.4 acres (9,000 yd^3 excavated soil) would be associated with constructing the Security Building, Administrative Building, Parking Lot, and the concrete batch plant/laydown area. All excavated soils will be stockpiled until they can be re-used to the extent practicable or sold and removed from the site. Holtec is requesting a license to store up to 8,680 MTUs in Phase 1 but has analyzed the environmental impacts of storing up to 100,000 MTUs at the CIS Facility.

Construction of Phases 2-20 would occur over approximately 20 years and would require an additional 210.6 acres of land. Such construction would occur adjacent to operational areas previously constructed. At full build-out, the CIS Facility would be constructed on approximately 330 acres. The Protected Area, which encloses the ISFSI Pads, would account for 283 acres of this total. Within the Protected Area, approximately 110 acres would be disturbed by the ISFSI Pads. There would be a buffer of more than 270 acres between the Protected Area boundary and the ISFSI Pads. All SNF stored within the Protected Area would be more than 500 feet from the Protected Area boundary and more than 1,000 feet from the property boundary. Phase 1 provides a bounding estimate for any construction impacts due to the associated support structures for these subsequent phases. The construction phases will be performed in sequence. Table 1.3 shows approximate durations for construction of phases 1-20 with the cumulative MTUs completed for each phase.

The major benefit of the Proposed Action is to authorize the receipt of the SNF currently in storage at the decommissioned shutdown sites, thus enabling the land at these sites to be returned to Greenfield status. After the land has been returned to Greenfield status, the communities that hosted the commercial reactor plants gain additional benefits as the land could potentially be redeveloped for other purposes. The Proposed Action also provides a regulatory path forward to receive SNF from other commercial reactors that may be decommissioned in the future, as well from operating commercial reactors prior to decommissioning. A CIS Facility serves as an interim storage facility until a geologic repository can be opened.

The proposed CIS Facility utilizes the technology licensed in Holtec's generic Certificate of Compliance for the Holtec International Storage Module Underground MAXimum Capacity (HI-STORM UMAX) Storage System, NRC docket number 72-1040. HI-STORM UMAX stores the canister containing SNF entirely below-ground to serve as a "security-friendly" storage facility, providing a clear, unobstructed view of the entire CIS Facility from any location and the closure lid is a massive steel weldment filled with concrete, virtually eliminating the storage contents as a target for malevolent acts. The CIS Facility does not require any utilities (water, compressed air, or electric power) for its operation post emplacement, eliminating any elements of vulnerability to terrorism. The subterranean stored contents emit a very small direct radiation dose to the facility

workers and surrounding environment. See Section 2.2 of this ER for a detailed description of the CIS Facility. The only pathway for public exposure to radiation from routine operations at the CIS Facility is external exposure at the uncontrolled boundary from the SNF casks stored at the ISFSI. There is no air pathway because the casks are sealed by being welded shut. There is no potential for a liquid pathway because the SNF contains no liquid component and the casks are sealed to prevent any liquids from contacting the SNF assemblies. Chapter 7 provides details regarding monitoring requirements for the CIS Facility.

The HI-STORM UMAX Storage System technology to be employed at the CIS Facility is currently licensed by the NRC in accordance with 10 CFR Part 72 and therefore complies with the NRC requirements for the independent storage of SNF. Holtec anticipates the SNF could be stored at the CIS Facility for up to 120 years, or until a permanent geologic repository is opened consistent with the NRC's Continued Storage Rule. The CIS Facility would be decommissioned at the end of facility life in accordance with 10 CFR 20, Subpart E.

Below is the anticipated schedule for the construction and operation of the proposed CIS Facility:

- Submit License Application in March 2017;
- Receive license 2019;
- Construction of Phase 1 of the CIS Facility begins in first quarter of 2020;
- Holtec CIS Facility commences operations in 2022.

Table 1.3

APPROXIMATE SCHEDULE OF ALL PROPOSED CONSTRUCTION PHASES FOR THE CIS FACILITY

Year	Construction Phase	Total Operating Capacity
1	1	0
2		
3	2	500
4	3	1,000
5	4	1,500
6	5	2,000
7	6	2,500
8	7	3,000
9	8	3,500
10	9	4,000
11	10	4,500
12	11	5,000
13	12	5,500
14	13	6,000
15	14	6,500
16	15	7,000
17	16	7,500
18	17	8,000
19	18	8,500
20	19	9,000
21	20	9,500
22-40	Operating Only Stage[1]	10,000

Note 1: It is expected that Decommissioning activities will overlap with the final years of the Operating Only Stage, however, the schedule of these activities will be determined at a later date.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION AND OFFICE OF NUCLEAR MATERIAL SAFETY AND SAFEGUARDS

RELATED TO REQUEST FOR DIRECT AND INDIRECT TRANSFERS OF CONTROL OF RENEWED FACILITY OPERATING LICENSE NO. DPR-28 AND THE GENERAL LICENSE FOR THE INDEPENDENT SPENT FUEL STORAGE INSTALLATION

FROM ENTERGY NUCLEAR OPERATIONS, INC. AND ENTERGY NUCLEAR VERMONT YANKEE, LLC

TO NORTHSTAR VERMONT YANKEE, LLC AND NORTHSTAR NUCLEAR DECOMMISSIONING COMPANY, LLC

VERMONT YANKEE NUCLEAR POWER STATION

DOCKET NOS. 50-271 AND 72-59

1.0 INTRODUCTION

By letter dated February 9, 2017 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML17045A140), including proprietary financial information provided as Enclosure 1P, “Membership Interest Purchase and Sales Agreement” (ADAMS Accession No. ML17045A139), and as supplemented by letters dated April 6, 2017 (ADAMS Accession No. ML17096A394), August 22, 2017 (ADAMS Accession No. ML17234A141), August 28, 2017 (ADAMS Accession No. ML17248A468), December 4, 2017 (ADAMS Accession No. ML17339A896), December 22, 2017 (ADAMS Accession No. ML18009A459), May 21, 2018 (ADAMS Accession No. ML18143B484), and June 28, 2018 (ADAMS Accession No. ML18183A220), Entergy Nuclear Operations, Inc. (ENOI), on behalf of itself and Entergy Nuclear Vermont Yankee, LLC (ENVY), and NorthStar Nuclear Decommissioning Company, LLC (NorthStar NDC) (together, “Applicants”), requested that the U.S. Nuclear Regulatory Commission (NRC) consent to the proposed direct and indirect transfer of the Vermont Yankee Nuclear Power Station (VY) Renewed Facility Operating License No. DPR-28 and the Vermont Yankee Independent Spent Fuel Storage Installation (ISFSI) general license (collectively referred to as the facility). Specifically, the Applicants requested that the NRC consent to the direct transfer of ENOI’s currently licensed authority (licensed operator for decommissioning) to NorthStar NDC. In addition, the Applicants requested the indirect transfer of control of ENVY’s ownership interests in the facility licenses to NorthStar Decommissioning Holdings, LLC, and its parents NorthStar Group Services, Inc. (NorthStar), LVI Parent Corp. (LVI) and NorthStar Group Holdings, LLC (Holdings). These direct and indirect transfer requests are submitted to NRC for approval pursuant to Section 184 of the Atomic Energy Act of 1954, as amended (AEA), “Inalienability of Licenses,” and Title 10 of the Code of Federal Regulations (10 CFR) 50.80, “Transfer of licenses,” 10 CFR 72.50, “Transfer of licenses,” and 10 CFR 50.90, “Application for amendment of license, construction permit, or early site permit.” Enclosure 1P contains

sensitive unclassified non-safeguards information (proprietary commercial and financial information) that is being withheld from public disclosure pursuant to 10 CFR 2.390.

The Applicants also requested that NRC approve a conforming administrative amendment to the facility license to reflect the proposed direct transfer of the license from ENOI to NorthStar NDC as well as a planned name change for ENVY, from ENVY to NorthStar Vermont Yankee, LLC (NorthStar VY).

Notice of NRC consideration of the application was published in the *Federal Register* (*FR*) on May 24, 2017 (82 *FR* 23845) and included an opportunity to comment, request a hearing, and petition for leave to intervene. The supplemental letters, listed above, contained clarifying information, did not expand the application beyond the scope of the original notice, and did not affect the applicability of the NRC no significant hazards consideration determination.

Upon approval of the proposed indirect transfer of control, ENVY would change its name to NorthStar VY, but the same legal entity would continue to exist before and after the proposed transfer. NorthStar VY would own the VY facility as well as its associated assets and real estate, including its nuclear decommissioning trust fund, title to spent nuclear fuel, and rights pursuant to the terms of its Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the U.S. Department of Energy (DOE). Certain off-site assets and real estate of ENVY are excluded, such as administrative offices and off-site training facilities. Following approval and implementation of the proposed direct transfer of control of the license, NorthStar NDC would become the licensed operator for decommissioning and assume licensed responsibility for VY through the direct transfer of ENOI's responsibility for licensed activities at VY to NorthStar NDC. NorthStar VY would also enter into an operating agreement with NorthStar NDC, which provides for NorthStar NDC to act as NorthStar VY's agent and for NorthStar VY to pay NorthStar NDC's costs of operation, including all decommissioning costs. Upon the proposed license transfer, NorthStar NDC would assume responsibility for compliance with the current licensing basis, including regulatory commitments that exist at the closing of the transaction between the Applicants, and would implement any changes under applicable regulatory requirements and practices.

2.0 BACKGROUND

The VY site is located in the town of Vernon, Vermont, in Windham County on the west shore of the Connecticut River immediately upstream of the Vernon Hydroelectric Station. VY employed a General Electric boiling water reactor nuclear steam supply system licensed to generate 1,912 megawatts (thermal energy). The operating license for VY was issued on March 21, 1972, and commercial operation commenced on November 30, 1972. The license was renewed on March 21, 2011.

By letter dated December 19, 2014 (ADAMS Accession No. ML14357A110), ENOI submitted the Post-Shutdown Decommissioning Activities Report (2014 PSDAR), including the Site-Specific Decommissioning Cost Estimate (DCE), for VY to the NRC. The 2014 PSDAR was submitted in accordance with the requirements of 50.82, "Termination of license," paragraph (a)(4)(i).

On January 12, 2015 (ADAMS Accession No. ML15013A426), pursuant to 10 CFR 50.82(a)(1)(i) and (a)(1)(ii), ENOI certified to the NRC that it had permanently ceased operations

at VY on December 29, 2014, and that all fuel had been permanently removed from the reactor vessel and placed in the spent fuel pool. In accordance with the PSDAR, ENOI placed the VY reactor in SAFSTOR and planned to have all VY spent fuel in dry storage in the onsite ISFSI by 2020, terminate the 10 CFR Part 50 license by 2073, and restore the site by 2075.

By letter dated August 16, 2018 (ADAMS Accession No. ML18234A143), ENOI submitted notification to NRC that all of the spent nuclear fuel assemblies had been transferred from the spent fuel pool and have been placed in dry storage within the onsite ISFSI.

Application for License Transfer

According to the license transfer application, the purpose of the proposed transfers of the licenses is to permit the accelerated radiological decommissioning of the non-ISFSI portions of the VY site. NorthStar NDC would assume possession of, and managerial responsibility for, all licensed activities, including decommissioning of the VY unit, and associated buildings and structures, and possession and licensing of the spent nuclear fuel, by the time the license transfer would be implemented. The principal remaining structures at VY include a reactor building, primary containment, control building, radioactive waste building, intake and discharge structures, turbine building, cooling towers, and main stack.

As the licensed operator, NorthStar NDC will be licensed to possess, maintain, and decommission the VY facilities and ISFSI and will be licensed to possess and maintain the spent nuclear fuel onsite. Under the terms of the proposed transaction, NorthStar NDC would begin decommissioning activities promptly after the transfer becomes effective and would plan to complete radiological decommissioning and restoration of the non-ISFSI portions of the VY site no later than the end of 2030 (and potentially as early as 2026).

NorthStar is a demolition, asbestos abatement, and environmental remediation company with experience in decommissioning large scale industrial and commercial complexes. NorthStar also has radiological decommissioning experience through involvement with the decommissioning of four research reactors at the Universities of Buffalo, Arizona, Illinois, and Washington, which were licensed by the NRC. In addition, according to the license transfer application, NorthStar has been involved with decommissioning at the US Department of Energy's Hanford and Savannah River sites and the deconstruction of nuclear reactor laboratory facilities at several universities, and has been awarded a contract to support the decommissioning of ten reactor sites in the United Kingdom.

According to the application, NorthStar NDC will draw on the experience of individuals from its parent company, NorthStar, and its strategic partners. NorthStar will contract with AREVA, Burns & McDonnell, and Waste Control Specialists as strategic partners to take advantage of their decommissioning experience, which includes NRC regulated power reactor vessel/internals segmentation and packaging, and spent fuel support (AREVA), NRC regulated quality assurance and compliance engineering experience and participation in NRC regulated decommissioning projects (Burns & McDonnell), and radioactive waste management, packaging, transportation, and disposal (Waste Control Specialists). The work of the strategic partners will be under the oversight of the NorthStar NDC's decontamination and decommissioning (D&D) Operations Manager.

Membership Interest Purchase and Sale Agreement

According to the license transfer application, NorthStar Decommissioning Holdings, LLC, proposes to acquire 100% of the membership interests in ENVY pursuant to the terms of the Membership Interest Purchase and Sale Agreement (MIPA) executed by ENVY and NorthStar; a copy of the MIPA is provided in a separately bound Addendum as Enclosure 1P to the February 9, 2017 application. Enclosure 1P contains confidential commercial and financial information that is being withheld from public disclosure pursuant to 10 CFR 2.390. A redacted, non-proprietary version of the MIPA, is provided as Enclosure 1 of the application (ADAMS Accession No. ML17045A140).

As such, indirect control of ENVY will be transferred from ENVY's current Entergy parent company, Entergy Nuclear Vermont Investment Co., LLC (ENVIC), to NorthStar Decommissioning Holdings, LLC, and its parents NorthStar, LVI, and Holdings. According to the Applicants, ENVY will immediately change its name to NorthStar VY, but the same legal entity will continue to exist before and after the proposed transfer. In addition, NorthStar NDC, a wholly owned subsidiary of NorthStar, will assume licensed responsibility for VY through a direct transfer of ENOI's licensed responsibility for decommissioning activities at VY to NorthStar NDC. NorthStar VY will enter into an operating agreement with NorthStar NDC, which provides for NorthStar NDC to act as NorthStar VY's agent and for NorthStar VY to pay NorthStar NDC's costs of operation, including all decommissioning costs. A simplified organization chart reflecting the current VY licensees and their owners is provided as Figure 1 of the application. The planned ownership following the proposed transfers is depicted in Figure 2 of the application.

Unlike corporations that have stockholders, a limited liability company (LLC) has membership interests. The membership interests in ENVY are currently held by ENVIC, an indirectly, wholly-owned subsidiary of Entergy Corporation. To facilitate the sale of ENVY, one day before the closing, ENVIC will transfer its membership interests in ENVY to a newly created ENVIC subsidiary, Vermont Yankee Asset Retirement Management, LLC (VYARM), which will then sell and transfer its membership interests to NorthStar Decommissioning Holdings, LLC. VYARM will hold the membership interests in ENVY for no more than 24 hours. As stated by the Applicants, this intermediate transfer step is a commercially integral part of the transfer of ownership in ENVY to NorthStar NDC. Therefore, considering the 24-hour limit for all intermediate transfer steps, the NRC staff finds it appropriate to consider the entire transaction, including the intermediate steps as a single license transfer application.

NorthStar Decommissioning Holdings, LLC, with NorthStar Group Holdings, LLC, and Entergy Nuclear Vermont Investment Company, LLC, with ENVY have entered into the MIPA that includes the direct and indirect transfers of control of ENOI's and ENVY's renewed facility operating license as well as the general license for the VY ISFSI. The transfers are for the licensed possession, maintenance, and decommissioning authorities so as to implement expedited decontamination, dismantlement, and decommissioning of the VY facilities (other than the ISFSI) as soon as reasonably practicable after the closing of the purchase and sale (Closing).

The MIPA requires NorthStar NDC and NorthStar VY to release all portions of the VY Site, other than the ISFSI, pursuant to 10 CFR 50.83, and to dispose of all radioactive waste, other than spent nuclear fuel, in accordance with all applicable laws as promptly as reasonably practicable

after closing the transaction. In addition, the MIPA also calls for NorthStar NDC and NorthStar VY to complete decommissioning with respect to the ISFSI and to terminate the NRC license as promptly as reasonably practicable after the U.S. Department of Energy accepts the spent nuclear fuel.

Under the terms of the MIPA, NorthStar NDC and NorthStar VY will become the NRC licensees responsible for all activities under the VY license. NorthStar NDC will perform the VY decommissioning, dismantlement, and decontamination work by relying on the experience of its parent, NorthStar Group Services Inc., as a general decommissioning contractor on commercial and industrial projects while performing decommissioning and decontamination work, including on asbestos projects, and through contracts with its strategic partners, AREVA, Burns & McDonnell, and WCS.

Revised PSDAR

In support of its license transfer application, NorthStar submitted to the NRC a revised Post-Shutdown Decommissioning Activities Report (revised PSDAR) for VY on April 6, 2017 (ADAMS Accession No. ML17096A394), to notify the NRC of changes in the actions and schedules previously described in the 2014 PSDAR. The revised PSDAR updates the information previously provided by ENOI, as required by 10 CFR 50.82(a)(7). The revised PSDAR is intended to apply based and contingent upon NRC approval of this license transfer, and ENVY being acquired by NorthStar, pursuant to the terms of the MIPA.

Vermont Public Utility Commission Certificate of Public Good and Settlement Agreement

Under Vermont state law, the Vermont Public Utility Commission (PUC) must also approve the transaction and issue an amended Certificate of Public Good (CPG). In addition to radiological decommissioning of the site to NRC decommissioning standards, NorthStar VY and NorthStar NDC will be required to restore the site in accordance with standards approved by the Vermont PUC in the amended CPG.

On March 2, 2018 (ADAMS Accession No. ML18066A735), the Applicants signed a settlement agreement and Memorandum of Understanding (MOU) with State of Vermont agencies and other interested parties on terms for approval of the proposed sale that, if the Applicants meet certain terms and conditions for the transfer of ownership of VY, will promote the general good of the State. In addition to NRC approval of the license transfer, the Vermont PUC approval of the MOU and a PUC order approving the proposed transaction are pre-conditions to closing of the proposed sale transaction between Entergy and NorthStar.

3.0 REGULATORY EVALUATION

As described in the application, the proposed transaction constitutes a direct and indirect transfer of ownership interest of VY, which requires prior NRC approval. For direct transfers of control of a license, the NRC must find that the direct transfer of the license is otherwise consistent with applicable provisions of law, NRC regulations, and orders issued by the Commission.

The request for approval of the direct and indirect transfer of the VY license as described above, and as discussed in this safety evaluation, is made pursuant to 10 CFR 50.80(a), which states that:

> No license for a production or utilization facility (including, but not limited to, permits under this part and part 52 of this chapter, and licenses under parts 50 and 52 of this chapter), or any right thereunder, shall be transferred, assigned, or in any manner disposed of, either voluntarily or involuntarily, directly or indirectly, through transfer of control of the license to any person, unless the Commission gives its consent in writing.

In addition, the regulations in 10 CFR 50.80(b) and (c) apply. The regulation at 10 CFR 50.80(b) states, in part:

> (1) An application for transfer of a license shall include:
>
> (i) For a construction permit or operating license under this part, as much of the information described in 50.33 and 50.34 of this part with respect to the identity and technical and financial qualifications of the proposed transferee as would be required by those sections if the application were for an initial license.

Section 50.80(c) of 10 CFR states, in part, that:

> …the Commission will approve an application for the transfer of a license, if the Commission determines: (1) That the proposed transferee is qualified to be the holder of the license; and (2) That transfer of the license is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission pursuant thereto.

Section 50.33(f) of 10 CFR states, in part, that:

> Except for an electric utility applicant for a license to operate a utilization facility of the type described in § 50.21(b) or § 50.22, [each application shall state] information sufficient to demonstrate to the Commission the financial qualification of the applicant to carry out, in accordance with regulations in this chapter, the activities for which the permit or license is sought.

The NRC staff applies guidance in NUREG-1577, Revision 1, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance" (ADAMS Accession No. ML013330264), issued February 1999, to evaluate the financial qualifications of applicants to carry out the activities for which the permit or license is sought.

Section 50.54(bb) of 10 CFR requires, in part, a licensee to submit, for NRC review and preliminary approval, the program by which the licensee intends to manage and provide funding for the management of all irradiated fuel at the reactor following permanent cessation of operation of the reactor until title to the irradiated fuel and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository.

In accordance with 10 CFR 50.2, "Decommission", means to remove a facility or site safely from service and reduce residual radioactivity to a level that permits (1) release of the property for unrestricted use and termination of the license, or (2) release of the property under restricted conditions and termination of the license.

Section 50.33(k)(1) of 10 CFR requires that applicants provide information, in the form of a report, as described in 10 CFR 50.75, "Reporting and recordkeeping for decommissioning planning," indicating how reasonable assurance will be provided that funds will be available to decommission the facility.

Section 50.75 of 10 CFR establishes requirements for indicating to NRC how a licensee will provide reasonable assurance that funds will be available for the decommissioning process. Section 50.75(b) requires that each power reactor applicant for an operating license submit a decommissioning report, as required by Section 50.33(k). Section 50.75(e) provides the methods acceptable to the NRC for providing decommissioning financial assurance. Finally, Section 50.75(h) provides additional requirements regarding the management of decommissioning trust funds.

Section 50.82(a)(8)(i) of 10 CFR states that decommissioning trust funds may be used by licensees if:

> (A) The withdrawals are for expenses for legitimate decommissioning activities consistent with the definition of decommissioning in § 50.2;
>
> (B) The expenditure would not reduce the value of the decommissioning trust below an amount necessary to place and maintain the reactor in a safe storage condition if unforeseen conditions or expenses arise and;
>
> (C) The withdrawals would not inhibit the ability of the licensee to complete funding of any shortfalls in the decommissioning trust needed to ensure the availability of funds to ultimately release the site and terminate the license.

Section 50.82(a)(8)(v) of 10 CFR requires power reactor licensees that have permanently ceased operations to provide to the NRC annually, by March 31, a decommissioning financial assurance status report.

Section 50.82(a)(8)(vii) of 10 CFR provides, in part, for the licensee's annual submittal to the NRC, a report on the status of its funding for managing irradiated fuel.

Section 50.34(a)(9) of 10 CFR requires applicants to provide:

> The technical qualifications of the applicant to engage in the proposed activities in accordance with the regulations in this chapter.

The NRC staff applies guidance in NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition," Chapter 13, "Conduct of Operations," Revision 6 of Section 13.1.1, "Management and Technical Support Organization" (ADAMS Accession No. ML15005A449), for the review of the corporate-level management and technical support organization of applicants. Guidance in Revision 7 of Section 13.1.2 and

13.1.3, "Operating Organization" (ADAMS Accession No. ML15007A296), is applied for the review of the operating organization of applicants, including the structure, functions, and responsibilities of the onsite organization established to safely operate and maintain the facility.

In addressing foreign ownership, control, or domination (FOCD) issues, Section 103d of the AEA provides, in relevant part that:

> No license may be issued to…any corporation or other entity if the Commission knows or has reason to believe it is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government.

The NRC's regulation in 10 CFR 50.38 is the regulatory provision that implements the FOCD provision of the AEA. Section 50.38 of 10 CFR provides, in part, that:

> [A]ny corporation, or other entity which the Commission knows or has reason to believe is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government, shall be ineligible to apply for and obtain a license.

The NRC staff evaluates license transfer applications in a manner consistent with the guidance provided in the "Final Standard Review Plan on Foreign Ownership, Control, or Domination," as published in the *Federal Register* on September 28, 1999 (64 FR 52357), to determine whether the applicant is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government.

The NRC staff also reviews information that relates to nuclear onsite property damage insurance requirements under 10 CFR 50.54(w) and the Price-Anderson insurance and indemnity requirements under Section 170 of the AEA and 10 CFR part 140, "Financial Protection Requirements and Indemnity Agreements."

With respect to the transfer of control of a license for an ISFSI, 10 CFR 72.50(a) states that:

> No license or any part included in a license issued under this part for an ISFSI or MRS [Monitored Retrievable Storage Installation] shall be transferred, assigned, or in any manner disposed of, either voluntarily or involuntarily, directly or indirectly, through transfer of control of the license to any person, unless the Commission gives its consent in writing.

Finally, with respect to the requested conforming license amendment, 10 CFR 50.90 states, in part, whenever a holder of a license, including a construction permit and operating license under this part, desires to amend the license or permit, an application for an amendment must be filed with the Commission fully describing the changes desired and following as far as applicable the form prescribed for original applications. Pursuant to 10 CFR 2.1315, where administrative license amendments are necessary to reflect an approved license transfer, such amendments will be included in the order that approves the license transfer.

4.0 FINANCIAL EVALUATION

4.1 Financial Qualifications

As explained above, on January 12, 2015, pursuant to 10 CFR 50.82(a)(1)(i) and (a)(1)(ii), ENOI certified to the NRC that it had permanently ceased operations at VY on December 29, 2014, and that all fuel had been permanently removed from the reactor vessel and placed in the spent fuel pool. Since NorthStar NDC (proposed licensed operator for decommissioning) will not be authorized under the facility license to operate or load fuel in the reactor pursuant to the terms of 10 CFR 50.82(a)(2), NorthStar NDC will not conduct the reactor operations contemplated by the financial qualifications provisions of 10 CFR 50.33(f)(2), but rather all of its licensed activities will involve possession of radioactive material in connection with maintaining the safe condition of the plant, radiological decommissioning of the VY site (including the ISFSI), license termination, and operational responsibilities associated with spent fuel management. Thus, following the proposed direct and indirect transfers, NorthStar VY (the proposed licensed owner) will maintain the existing Nuclear Decommissioning Trust (NDT) and will be responsible for funding all the expenses associated with radiological decommissioning and operational costs for spent fuel management. Accordingly, as described in this safety evaluation, the staff's review of the Applicants' financial qualifications and decommissioning financial assurance pursuant to 10 CFR 50.33(f), 10 CFR 50.33(k)(1), 10 CFR 50.75, and 10 CFR 50.82(a), includes an analysis of the projected costs for decommissioning the facility and terminating the license, and managing irradiated fuel until the U.S. Department of Energy takes title and possession of the fuel.

For a facility in decommissioning, a licensee is required to execute financial plans for spent fuel management under 10 CFR 50.54(bb) and report annually on the status of funding dedicated towards radiological decommissioning and spent fuel management under 10 CFR 50.82(a)(8)(v) to (vii).

4.2 Radiological Decommissioning

Pursuant to NRC regulations in 10 CFR 50.2, "Decommission", means to remove a facility or site safely from service and reduce residual radioactivity to a level that permits: (1) release of the property for unrestricted use and termination of the license, or (2) release of the property under restricted conditions and termination of the license. The existing NDT for VY was created in compliance to 10 CFR 50.75, and the funds within the trust were collected while the facility was operating. As described below, the NRC staff's review of decommissioning financial assurance assesses whether the Applicants have provided reasonable assurance of obtaining the funds necessary to cover estimated costs for radiological decommissioning of VY and its ISFSI.

Separate from this application, by letter dated April 6, 2017, the Applicants provided a revised PSDAR[1] in support of the proposed direct and indirect license transfers. Specifically, the revised PSDAR contains:

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[1] The staff notes that the NRC does not review the PSDAR for approval; however, for the purpose of this license transfer request, the staff relied on the revised PSDAR as a reference for the Applicant's decommissioning plans.

1. A description of the planned decommissioning activities along with a schedule for their accomplishment;
2. A discussion that provides the reasons for concluding that the environmental impacts associated with site-specific decommissioning activities will be bounded by previously issued environmental impact statements;
3. A site-specific decommissioning cost estimate, including the projected irradiated fuel management costs, license termination costs, and site restoration costs; and
4. A settlement agreement between ENOI, ENVY (NorthStar VY after its acquisition by NorthStar), and agencies of the State of Vermont.

The 2014 PSDAR, as originally submitted by ENOI and ENVY reflected the current decommissioning plan of VY to be completed by ENOI and ENVY within a 60-year period using the SAFSTOR method. The revised PSDAR reflects NorthStar's plan to complete the immediate and accelerated decommissioning of the non-ISFSI portions of the VY site within a 7-year period after the proposed transfer is approved. The revised PSDAR also contains the most recent decommissioning cost estimate and spent fuel management plans pursuant to 10 CFR 50.82, "Termination of License."

Under the revised PSDAR, as compared to ENOI and ENVY's 2014 PSDAR, the proposed change in decommissioning method from SAFSTOR to DECON results in an overall 23-year acceleration of the site closure from 2075 to approximately 2052, and a site-specific decommissioning cost estimate that reflects an approximate license termination cost reduction in an amount of $200 million, and an increase in spent fuel management costs of approximately $61 million.

In its original request, by letter dated February 9, 2017, the Applicants provided financial projections for the duration of the VY decommissioning project, including the amount of the decommissioning trust funds in the NDT (~$562 million as of December 31, 2016), a financial Support Agreement in the amount of $125 million, estimated costs for the radiological decommissioning of VY (~$495 million), spent fuel management costs to be paid for using the NDT (up to $20 million at any one time repaid by DOE reimbursements), and estimated costs for decommissioning the ISFSI (~$3.5 million).

By letter dated November 3, 2017 (ADAMS Accession Number ML17313A431), the staff requested additional information regarding the Applicants' reliance on use of the NDT for spent fuel management. In response, by letter dated December 4, 2017 (ADAMS Accession Number ML17339A896), the Applicants explained that there were material changes in circumstances from the analysis upon which the original exemption was based, but believed that the previous exemption granted to Entergy for use of the NDT for spent fuel management expenses should be transferred to them.

Based on its review of the information supplied to date in the original application and supplemental information provided in response to these RAIs, the NRC staff was unable to find that the funding mechanisms (use of the NDT for spent fuel management) proposed by the Applicants were adequate to provide reasonable assurance that sufficient funds would be available for the decommissioning of the VY facility and for the management of spent fuel. Specifically, with respect to sufficiency of the NDT, the staff was concerned that the previous showing by Entergy of special circumstances in granting of the exemption to use the NDT for spent fuel management did not appear to apply to NorthStar, in that a 60-year period would not

be available for funds in the NDT to grow to a level sufficient to pay for both projected decommissioning costs and spent fuel management. Therefore, by letter dated April 5, 2018 (ADAMS Accession Number ML18045A817), the staff requested additional information on the applicability of the exemption granted to Entergy to use the NDT for spent fuel management.

In response, by letters dated May 21, 2018 (ADAMS Accession Number ML18143B484) and June 28, 2018 (ADAMS Accession Number ML18183A220), the Applicants provided an analysis of the applicability of the current Entergy exemption to use the NDT for spent fuel management concluding that the special circumstances of the exemption apply, because NorthStar VY has committed to limiting any access to funds for purposes of spent fuel management to $20 million on a "revolving" basis and to return recoveries for ISFSI expenses from DOE reimbursements to the trust fund. In addition, NorthStar claimed that precluding access to $20 million in excess funds would create an unnecessary financial burden without any corresponding safety benefit. Nevertheless, on May 25, 2018, NorthStar submitted an exemption request to use up to $20 million from the NDT on a revolving basis for spent fuel management activities (ADAMS Accession Number ML18150A315). The staff's analysis of this regulatory exemption was performed separate from this safety evaluation and, on October 11, 2018, the NRC staff approved the exemption request (ADAMS Accession No. ML18274A246). This exemption is being issued simultaneously with this license transfer, and will only apply to NorthStar VY and NorthStar NDC following consummation of the license transfer transaction and NRC issuance of the conforming amendment reflecting this license transfer. In its review of the exemption, the staff concluded that reasonable assurance exists that adequate funds will be available in the NDT to complete radiological decommissioning, license termination, and the spent fuel management activities within the scope of this exemption request. The staff's findings from its evaluation of the exemption were considered in its analysis of this proposed license transfer and supports the staff's conclusion that the Applicants' use of the NDT in a limited capacity ($20 million on a revolving basis), as projected to be reimbursed by funds recovered from DOE litigation, will not have a negative impact on the adequacy of funding for radiological decommissioning.

On March 2, 2018, the Applicants, certain State of Vermont agencies, and others entered into a settlement agreement concerning the proposed purchase and sale transaction of VY from Entergy to NorthStar (ADAMS Accession No. ML18066A044). The staff noted that the settlement agreement included language that appeared to conflict with NRC regulations on the appropriate use of the NDT in that the settlement agreement established an escrow account that may be used to fund completion of decommissioning and/or site restoration activities. Specifically, the source of funding for this account was unclear, and the settlement agreement language suggested, in part, that funds withdrawn from the NDT for decommissioning expenses could be deposited into the escrow account which would be prohibited by NRC regulations in 10 CFR 50.82(a)(8)(i)(A) which requires that funds in the NDT be used only for activities consistent with the definition of decommissioning in 10 CFR 50.2. Therefore, by letter dated April 5, 2018, the staff requested additional information on the impact of the applicant's settlement agreement with the State and others on its ability to meet NRC's financial qualification requirements.

As additional financial assurance in support of the settlement agreement, the Applicant's RAI response dated May 21, 2018, notes that the Applicants will deposit $30 million into an escrow account that will be funded with $20 million from Entergy and $10 million from NorthStar. The Applicants stated that funds contributed to, and accumulated in, this escrow account will be available for radiological decommissioning and site restoration, as needed.

The staff further notes that after the initial funding of the escrow account at closing, NorthStar NDC and its subcontractors will immediately conduct decommissioning activities. According to the Applicants RAI response, NorthStar NDC will submit invoices for that decommissioning work to NorthStar VY, which will withdraw funds from the NDT to pay for these invoices. After NorthStar VY has withdrawn the first $100 million from the NDT, however, it will not immediately pay NorthStar NDC 100% of the amounts invoiced and withdrawn from the NDT, but rather will withhold 10% of these amounts and deposit the withheld 10%, up to $25 million, into the escrow account. NorthStar NDC has committed to defer receipt of payment (up to $25 million) for the decommissioning work that it and its subcontractors perform. Based on its evaluation of the RAI response, the NRC staff finds that funds withdrawn from the NDT will only be used to pay for legitimate decommissioning expenses. Further, the staff finds that the terms and conditions of the settlement agreement do not have any adverse effect on the financial information submitted by the Applicants to the NRC regarding the license transfer application because the settlement agreement establishes additional and enhanced funding mechanisms that do not rely on funds from the NDT to assure that site restoration beyond what is required by the NRC will be completed as planned.

According to the Applicant's RAI response dated May 21, 2018, the latest estimated cost to decommission VY was approximately $495 million (2016 dollars), plus an additional approximately $3.5 million for ISFSI decommissioning. The latest estimated opening NDT balance in 2019 (the estimated start date of decommissioning) will be approximately $513 million. However, according to one scenario in its June 28, 2018 supplemental RAI response where NorthStar trust fund income taxes are paid prior to closing of the proposed transfer, the estimated opening NDT balance could be approximately $488 million without considering future trust contributions and growth. Therefore, the staff used this conservative estimate of the opening NDT balance to perform its independent cash flow analysis provided in Attachment 1 to this safety evaluation report.

With respect to the adequacy of funding for the radiological decommissioning of VY and the VY ISFSI, the NRC staff reviewed the application and RAI responses, including Applicant's proposed site-specific decommissioning cost estimate for the facility, planned decommissioning activities, use of the NDT for spent fuel management, the most conservative opening NDT balance in 2019 ($488 million), and projected trust growth. In its analysis, the staff considered the NDT opening balance of $488 million, plus the $30 million dollar escrow account described above, the financial Support Agreement in the amount of $140 million, the $20 million revolving credit from DOE reimbursements and/or the performance bonds, and a 2% real-rate of return on annual balances. These considerations were included in the staff's independent cash flow analysis is contained in Attachment 1 to this safety evaluation. Based on its evaluation as shown in its cash flow analysis, the NRC staff finds that the funds in the NDT are expected to be available and sufficient to cover the estimated costs for the radiological decommissioning of the facility (including the ISFSI), and spent fuel management to the extent as allowed permitted by the approval of the regulatory exemption ($20 million on a revolving basis).

Conclusion

Based on this review, in consideration of the above analysis and the staff's independent cash flow analysis in Attachment 1 of this safety evaluation, the NRC staff finds that the Applicants have provided reasonable assurance of obtaining the funds necessary to cover estimated costs

for decommissioning VY and its ISFSI in accordance with the requirements of 10 CFR 50.33(f), 10 CFR 50.33(k)(1), 10 CFR 50.75, and 10 CFR 50.82(a).

4.3 Spent Fuel Management

After the closing of the proposed transaction, NorthStar VY will retain ownership and title to all spent nuclear fuel and all rights and obligations under the Standard Spent Fuel Disposal Contract. The Nuclear Decommissioning Trust is to be retained by NorthStar Vermont Yankee, LLC. NorthStar VY will also be responsible for ISFSI decommissioning.

In its license transfer application, by letter dated February 9, 2017, the Applicants provided their funding plan for spent fuel management costs, which included using excess decommissioning trust funds for spent fuel management up to $20 million on a revolving basis, reliance on DOE reimbursements for spent fuel management costs to be repaid to the NDT, and a financial Support Agreement in the amount of $125 million. The NRC staff's review of the Applicants' funding plan for spent fuel management costs is discussed below.

Exemption to use NDT for Spent Fuel Management

The Applicants proposed to use excess decommissioning trust funds for spent fuel management relying on the regulatory exemption granted to Entergy in 2015. As discussed in Section 4.2 of this evaluation, the staff was concerned that the previous showing by Entergy of special circumstances in granting of the exemption to use the NDT for spent fuel management did not apply to NorthStar, because Entergy's 60-year SAFSTOR period would not be available to NorthStar for funds in the NDT to grow to a level sufficient to pay for both projected decommissioning costs and spent fuel management. As explained above, this issue was discussed in the RAIs dated November 3, 2017, and April 5, 2018, and the applicant's responses dated December 4, 2017, and May 21, 2018.

By letter dated May 25, 2018, in support of the license transfer request, NorthStar submitted a request for an exemption to 10 CFR 50.82(a)(8)(i)(A) to use up to $20 million of the VY trust (on a revolving basis) to pay for spent fuel management expenses. As mentioned above, the staff's analysis of this regulatory exemption was performed separate from this safety evaluation and, on October 11, 2018, the NRC staff approved the exemption request (ADAMS Accession No. ML18274A246). This exemption is being issued simultaneously with this license transfer, and will only apply to NorthStar VY and NorthStar NDC following consummation of the license transfer transaction and NRC issuance of the conforming amendment reflecting this license transfer. The staff's findings from its evaluation of the exemption were considered in its analysis of the proposed license transfer and supports the conclusion that use of the NDT in a limited capacity ($20 million on a revolving basis), as projected to be reimbursed by funds recovered from DOE litigation, will not have a negative impact on the adequacy of funding for radiological decommissioning. These findings are supported by the staff's independent cash flow analysis.

Based on its evaluation, the NRC staff finds that the use of $20 million from the NDT for spent fuel management, on a revolving basis, and as projected to be reimbursed by funds recovered from DOE litigation, provides a reasonable source of funding to cover the costs associated with spent fuel management because such use will not have a negative impact on the adequacy of funding for radiological decommissioning, as confirmed by the regulatory exemption described above.

DOE Reimbursements

Based on its review of the license transfer application, the NRC staff also had questions regarding the ability of the Applicants' to rely on DOE reimbursements for spent fuel management costs. Therefore, by letter dated November 3, 2017, the staff requested additional information regarding the reliability of the recovery of claims from DOE to reimburse the NDT.

In response, by letter dated December 4, 2017 (ADAMS Accession Number ML17339A896), NorthStar provided further justification for why they believed that DOE reimbursements for spent fuel management expenses should be considered a reliable source of funding (to reimburse the NDT), including submittal of an Inspector General Financial Audit on DOE's Nuclear Waste Fund.

Based on its review of the information supplied to date in the original application and supplemental information provided in response to these RAIs, the NRC staff was unable to find that the DOE reimbursements provided a reasonable source of additional funding to supplement estimated costs for spent fuel management at the site. Specifically, Entergy did not yet appear to have filed a claim for DOE reimbursements that could be relied upon for spent fuel management costs after the requested license transfer, nor show that a favorable judgment has been obtained for recovery of those costs. In addition, NorthStar would not have a settlement agreement in place with DOE for the recovery of spent fuel management costs immediately following the proposed transfer. Therefore, by letter dated April 5, 2018, the staff requested additional information on NorthStar's plans for the recovery of claims from DOE.
According to the Applicant's RAI response dated May 21, 2018, ENVY has successfully filed two rounds of claims for DOE reimbursements receiving approximately $41 million (April 11, 2013) and $19 million (June 27, 2016). As stated in the application, NorthStar is expecting to receive its own DOE reimbursements to recover costs for spent fuel management.

In the RAI response dated May 21, 2018, the Applicants also indicated that the DOE reimbursements for spent fuel management expenses require a licensee to litigate for DOE reimbursements, and that no such litigation has been initiated since the last DOE reimbursement. However, ENVY has current contractual rights under the Standard Contract and believes they are entitled to compensation for damages that continue to incur until the time of the license transfers. The Applicants further stated that given the governing law with respect to government contracts, costs must first be incurred before ENVY can make a claim for damages. According to the Applicants, although ENVY could have filed claims more frequently, ENVY has elected to allow damages to accumulate over several years before filing a claim in order to avoid excessive litigation-related costs. The staff notes that under a Vermont Settlement Agreement, ENVY has committed to file a "Round 3" claim no later than 30 days after the completion of the dry fuel storage campaign. ENVY anticipates it will seek, among other costs, approximately $145 million in damages for the dry fuel storage campaign and approximately $30 million for ISFSI operating and maintenance (O&M) costs from 2014 through the date of filing the claim. Additionally, an expected "Round 4" claim would be filed between 2020 and 2023 to recover ISFSI O&M for the period from the end of the Round 3 claim through the time of Round 4 claim. According to the Applicants, filing lawsuits more frequently would require time and effort, as well as legal costs that can be avoided by consolidating claims for several years into one lawsuit. NorthStar NDC proposes to follow much the same strategy to obtain DOE reimbursements for the VY spent fuel management expenses incurred upon obtaining the licenses.

As further assurance regarding its reliance on a future DOE settlement agreement, NorthStar VY proposed, in the May 21, 2018, RAI response, and agrees to the following license condition:

> NorthStar VY shall obtain a performance bond if a Settlement Agreement with the U.S. Department of Energy (DOE), on DOE reimbursements for spent fuel management expenses is not entered into by January 1, 2022. The performance bond will be effective January 1, 2022, initially in the amount of $4.3 million, and it will be renewed annually. This amount covers the annual amount of ISFSI operation and maintenance (O&M) costs projected for 2022-2024. If a settlement is not reached by January 1, 2024, this amount will be increased to $9.3 million, which covers the annual amount of ISFSI O&M costs projected for years after 2024.

The staff notes that, in the May 21, 2018, RAI response, Attachment 2, "Response to Request for Additional Information," the Applicants provided as Enclosure 5, "Prequalification Letter," a prequalification letter from Aspen American Insurance Company and Everest Reinsurance Company, to demonstrate NorthStar's ability to obtain the $4.3 million and $9.3 million performance bonds, as needed, for spent fuel management.[2]

With this safety evaluation, in this circumstance, the NRC staff finds that the assumption of DOE reimbursement is a reasonable source of additional funding. In recent years DOE reimbursements have become more consistent and predictable despite the longevity of the litigation process and complexity of DOE standard settlement agreements. Moreover, ENVY (to be renamed NorthStar VY), has successfully filed two rounds of claims for DOE reimbursements. Finally, as further assurance of its reliance on a future DOE settlement agreement, NorthStar VY agreed to a license condition committing to obtain a performance bond to cover spent fuel management costs if a settlement agreement has not been reached in timeframe anticipated. Therefore, the NRC staff concludes that DOE reimbursements, as proposed by the Applicants, provide a reasonable source of funds to cover costs associated with the management of spent fuel for this financial qualifications review.

Support Agreement

Based on its review of the license transfer application, the NRC staff questioned the adequacy of the Applicants' financial Support Agreement amount of $125 million. Therefore, by letter dated November 3, 2017 (ADAMS Accession Number ML17313A431), the staff requested additional information regarding the adequacy of the proposed financial Support Agreement from NorthStar for decommissioning funding and spent fuel management costs.

In response, by letter dated December 4, 2017 (ADAMS Accession Number ML17339A896), NorthStar provided further justification for the adequacy of its financial Support Agreement. By letter dated December 22, 2017 (ADAMS Accession Number ML18009A459), the Applicants supplemented their response to NRC's requests for additional information (RAIs) dated

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[2] According to the Applicants, NorthStar expects to use $20 million from the VY NDT, which would cover the cumulative ISFSI O&M costs through the end of 2021 and beginning of 2022. Thus, the Applicants state that the performance bond would commence in the first year that funds would be required from another source, and the performance bond would continue annually and be increased to cover the estimated costs until a DOE settlement agreement is formally executed.

November 3, 2017. In its response, NorthStar informed NRC that it had determined that the Support Agreement amount needed to be increased from $125 million to $140 million.

Based on its review of the information supplied to date in the original application and supplemental information provided in response to these RAIs, the NRC staff was unable to find that the financial Support Agreement proposed by the Applicants adequate to ensure that sufficient funds would be available for the management of spent fuel. Specifically, it was unclear to staff how the NRC could rely on the financial Support Agreement as “an additional source of available funding,” to operate and maintain the ISFSI until DOE takes title and possession of the fuel, when the “No Guarantee” term of the Support Agreement specifically stated that the agreement was not a guarantee and the Support Agreement did not constitute a parent company guarantee as described in NRC regulations.

Therefore, by letter dated April 5, 2018 (ADAMS Accession Number ML18045A817), the staff requested additional information on the ability of the proposed financial Support Agreement to provide an available source of funding in the absence of a guarantee. In response, by letters dated May 21, 2018 (ADAMS Accession Number ML18143B484) and June 28, 2018 (ADAMS Accession Number ML18183A220), the Applicants provided clarifying language for the proposed financial Support Agreement (of $140 million) and supporting financial qualification information that clarifies the intent of the Support Agreement. Specifically, the Applicants made several revisions to the proposed Support Agreement, including the addition of clarifying language that the Support Agreement, “may, however, be relied upon by the NRC as a parental guarantee in determining the financial qualifications of the Subsidiary to hold the NRC License, including funding the costs associated with the spent fuel management program . . . .”

As further assurance that NorthStar VY and NorthStar NDC will continue to have an adequate source of funds for spent fuel management costs, the Applicants proposed the following license condition:

> NorthStar Vermont Yankee, LLC and NorthStar Nuclear Decommissioning Company, LLC shall take no action to cause NorthStar Group Services, Inc., to void, cancel, or modify the $140 million Support agreement to provide funding for Vermont Yankee as represented in the application without prior written consent of the Director of the Office of Nuclear Reactor Regulation.

Based on the staff’s evaluation of the application, RAI responses, and proposed license condition, the staff’s concerns related to the support agreement have been resolved because the Applicants provided clarifying revised language for the proposed financial Support Agreement, supporting financial qualification information, and clarification that the intent of the Support Agreement is to provide a reasonable source of funding for spent fuel management. Therefore, based on the original application, as supplemented by the RAI responses, the NRC staff finds that the $140 million financial Support Agreement provides a reasonable source of funding to cover the estimated costs associated with spent fuel management.

Conclusion

As the application and RAI responses pertained to the funding for spent fuel management, the NRC staff reviewed the Applicant's proposed site-specific decommissioning cost estimate for the facility, planned decommissioning activities, use of the NDT for spent fuel management (~$288 million), the most conservative opening NDT balance in 2019 ($488 million), and projected trust growth. In its analysis for spent fuel management, the staff considered the NDT opening balance of $488 million, the financial Support Agreement in the amount of $140 million, the $20 million revolving credit from DOE reimbursements and/or the performance bonds, and a 2% real-rate of return on annual balances. Based on its evaluation, the NRC staff finds that these funds are expected to be available to pay for the radiological decommissioning of the facility (including the ISFSI), and spent fuel management as allowed by the approval of the regulatory exemption. The staff's independent cash flow analysis is contained in Attachment 1 to this safety evaluation report.

Based on its review, in consideration of the above analysis describing the Applicants' financial plans for managing spent fuel, the NRC staff finds that the Applicants have reasonable assurance of obtaining the funds necessary to cover estimated costs for irradiated fuel management in accordance with 10 CFR 50.33(f) and 10 CFR 50.54(bb).

4.4 Financial Qualifications Conclusion

As described above, the NRC staff reviewed the application and RAI responses in its evaluation of the Applicants' financial qualifications, funding for the decommissioning of VY and the VY ISFSI, and funding for irradiated fuel management at VY. Based on its evaluation as described above and shown in its cash flow analysis, the NRC staff concludes that the funds in the NDT are expected to be available and sufficient to cover the estimated costs for the radiological decommissioning of the facility (including the ISFSI), and spent fuel management to the extent allowed by the approval of the regulatory exemption ($20 million on a revolving basis). Therefore, the NRC staff concludes that the Applicants have provided reasonable assurance of obtaining the funds necessary to cover estimated costs for decommissioning VY and its ISFSI in accordance with the requirements of 10 CFR 50.33(f), 10 CFR 50.33(k)(1), 10 CFR 50.75, and 10 CFR 50.82(a).

In addition, based on its evaluation above of the Applicants' funding plans for managing spent fuel, including exemption to use NDT for Spent Fuel Management, the NorthStar $140 million financial Support Agreement, and the projected DOE reimbursements and/or performance bonds, as supported by the staff's independent cash flow analysis, the NRC staff concludes that the Applicants have reasonable assurance of obtaining the funds necessary to cover estimated costs for spent fuel management in accordance with the requirements of 10 CFR 50.33(f), and 10 CFR 50.54(bb).

Accordingly, in light of the foregoing evaluation, the NRC staff finds that NorthStar VY and NorthStar NDC are financially qualified to hold the VY License No. DPR-28 as proposed.

5.0 STANDARD CONTRACT FOR DISPOSAL OF SPENT NUCLEAR FUEL

Upon closing, NorthStar VY (who upon approval of the proposed indirect transfer of control, would be the same legal entity as ENVY but with a name change to NorthStar VY) will continue

to hold title to the spent nuclear fuel at VY and will continue to maintain the DOE Standard Contract, including all rights and obligations under that contract. This Standard Contract, No. DE-CR01-83NE44431 (DOE Standard Contract), was entered into by the previous owner, Vermont Yankee Nuclear Power Corporation, and the United States of America, represented by the DOE, to govern the disposal of spent nuclear fuel generated at VY. NorthStar NDC will have exclusive responsibility under the Licenses for the possession, maintenance, and decommissioning of VY, which includes responsibility for spent fuel management and the maintenance and security of the ISFSI.

6.0 ANTITRUST REVIEW

The AEA does not require or authorize antitrust reviews of post-operating license transfer applications (*Kansas Gas and Electric Co., et al* (Wolf Creek Generating Station, Unit 1), CLI-99-19, 49 NRC 441 (1999)). This application postdates the issuance of the operating license for the unit under consideration in this safety evaluation, and, therefore, no antitrust review is required or authorized.

7.0 FOREIGN OWNERSHIP, CONTROL, OR DOMINATION

Sections 103d and 104d of the AEA prohibit the NRC from issuing a license for a nuclear power plant to "any corporation or other entity if the Commission knows or has reason to believe it is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government." The NRC's regulation, 10 CFR 50.38, contains language to implement this prohibition.

According to the application, the direct license transfer application provides that NorthStar Group Holdings, LLC, and its subsidiaries, are not owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government. NorthStar Group Holdings, LLC (Holdings) is privately held and controlled by its Board of Directors, all of whom are U.S. citizens. The Directors are appointed by the U.S. citizens who control the private equity funds that own Holdings. Each of the funds has multiple limited partnership investors, who are passive investors. The passive investors may include foreign investors, but Holdings is not aware of any foreign passive investor that holds more than 5 percent of the indirect ownership interests of Holdings. Moreover, the passive investors are not able to exercise control over either the private equity funds or Holdings. As such, there is no reason to believe that Holdings and the licensee entities will be owned, controlled or dominated by any foreign person. The current directors and executive officers of Holdings are U.S. citizens. Neither NorthStar NDC nor NorthStar VY are acting as an agent or representative of any other person in the proposed transfers of the licenses.

Based on this information, the NRC staff finds that the transfer of ownership and decommissioning authority of the facility to NorthStar NDC and NorthStar VY as proposed in the application does not raise any issues related to FOCD within the meaning of the AEA and NRC regulations. In light of the above and pursuant to Sections 103d and 104d of the AEA and 10 CFR 50.38, the NRC staff concludes that it does not know, or have reason to believe, that NorthStar VY will be owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government, as a result of the direct or indirect license transfers.

8.0 NUCLEAR INSURANCE AND INDEMNITY

Pursuant to the requirements of the Price-Anderson Act (Section 170 of the AEA) and the NRC's implementing regulations in 10 CFR part 140, the current indemnity agreement must be modified to reflect that, after the proposed license transfers take effect, NorthStar VY (licensed owner) and NorthStar NDC (licensed operator for decommissioning) will be the sole licensees for VY for purposes of decommissioning the site. Consistent with NRC practice, the staff will require NorthStar VY and NorthStar NDC to provide and maintain onsite property insurance as specified in 10 CFR 50.54(w), "Conditions of licenses." NorthStar VY and NorthStar NDC are also required to provide evidence that they have obtained the appropriate amount of insurance in accordance with 10 CFR 140.11(a)(4), which will be effective concurrent with the date of the license transfers and amended indemnity agreement. Therefore, the order approving the transfer will be conditioned as follows:

> "Prior to the closing of the license transfer, NorthStar NDC and NorthStar VY shall provide the Directors of NRC's Office of Nuclear Material Safety and Safeguards (NMSS) and Office of Nuclear Reactor Regulation (NRR) satisfactory documentary evidence that they have obtained the appropriate amount of insurance required of a licensee under 10 CFR 140.11(a)(4) and 10 CFR 50.54(w) of the Commission's regulations, consistent with the exemptions issued to VY on April 15, 2016."

Based on the above, the NRC staff concludes that the proposed license transfer, as conditioned, satisfies the nuclear insurance and indemnity requirements of 10 CFR part 140 and 10 CFR part 50.

9.0 TECHNICAL EVALUATION

9.1 Management and Technical Support Organization

NorthStar NDC and NorthStar VY

NorthStar NDC and NorthStar VY will be required to comply with all the requirements of the VY current NRC licenses and applicable NRC regulations upon transfer of the licenses. As stated in the license transfer application, NorthStar NDC and NorthStar VY will possess or have access to all records necessary for compliance with their obligations under the licenses and NRC requirements. NorthStar NDC will assume responsibility for compliance with the current licensing basis, including regulatory commitments that exist at closing. Any changes to the current licensing basis will be implemented under applicable regulatory requirements and practices.

NorthStar NDC will not be authorized under the facility license to operate or load fuel in the reactor, but rather will be licensed to possess radioactive material, decommission the VY facilities and site, operate the onsite ISFSI, and to terminate the license. Therefore, the application was evaluated against the requirements of 10 CFR 50.34(a)(9) and 10 CFR 50.80 that the applicant be technically qualified to engage in the proposed activities to possess radioactive material, decommission the VY facilities and site, operate the onsite ISFSI and to terminate the license. In support of that evaluation, the NRC staff reviewed the application in accordance with the acceptance criteria contained in NUREG-0800, Section 13.1.1, Revision 6

(ADAMS Accession No. ML15005A449) to determine the acceptability of the proposed corporate management and technical support organization, and ANSI/ANS-3.1-2014 (Section 4.3.3, “Radiation protection”) that has been endorsed by NRC in Draft Regulatory Guide DG-1329, “Qualification and Training of Personnel for Nuclear Power Plants” (ADAMS Accession No. ML16091A267).

As stated in the application, NorthStar NDC employees and contractors will not be employed without being qualified for their positions in accordance with the applicable VY Technical Specifications and Quality Assurance Program Manual requirements. NorthStar NDC will also adopt the existing Quality Assurance (QA), emergency preparedness, and training procedures currently in place at VY and establish these functions at VY using NorthStar NDC project personnel that will include existing VY personnel, as well as contractors.

The Applicants state that the existing ISFSI operations employees of Entergy at VY and other key members of the existing ISFSI operations team are expected to become NorthStar NDC employees. Approximately 15 employees will be offered employment with NorthStar NDC. In addition, NorthStar NDC plans to retain the existing security subcontractor.

As stated in the application and/or supplemental information, NorthStar NDC will staff a Radiation Protection Manager who reports to the Director of Health Physics and Waste Operations. Specifically, the NorthStar Radiation Protection Manager at the Vermont Yankee Nuclear Station will be the current Entergy Radiation Protection Manager at VY, and he will become a NorthStar NDC employee upon the transaction closing. The Radiation Protection Manager will typically be responsible for the development and administration of programs and policies in the specific areas of radiation protection. The proposed Radiation Protection Manager has the education, training, and experience to fulfill the requirements of ANSI/ANS-3.1-2014 (Section 4.3.3, Radiation Protection) middle level manager and radiation protection manager.

An organization chart showing the planned project organization is provided in Enclosure 3 to the application (as modified by updated information in the May 21, 2018 RAI response). The organization provides for a single Vice President and Decommissioning Program Manager (PM) accountable for overall management, leadership, performance, nuclear safety, QA and employee safety. Managers reporting directly to the PM will have responsibilities for radiological safety, industrial health and safety, fuel storage, regulatory affairs, quality assurance, licensing, environmental, decontamination and decommissioning, engineering and operations, waste operations, project administration and financial services, and project controls.
This organization will provide a nuclear management team with control over the decontamination and decommissioning operations.

Strategic Partner Experience and Expertise

According to the application, NorthStar NDC will draw on the experience of individuals from its parent company, NorthStar, and its strategic partners. NorthStar will contract with AREVA, Burns & McDonnell, and Waste Control Specialists as strategic partners to take advantage of their decommissioning experience. The experience and expertise of NorthStar and each of its strategic partners is briefly described below:

NorthStar Group Services, Inc. is a demolition and asbestos abatement company. As a demolition and abatement contractor, NorthStar has experience in demolition and decommissioning including participation in the decommissioning of four NRC regulated research reactors at the Universities of Buffalo, Arizona, Illinois and Washington. NorthStar has also been involved with decommissioning at the DOE's Hanford and Savannah River sites. The NorthStar organization will consist of existing staff from VY and current VY contractors, and staff from NorthStar and its strategic partners. An organization chart of the proposed management structure was provided in the application as Enclosure 3, along with the resumes of key management personnel.

AREVA, Inc. (now known as Orano USA LLC) is a nuclear fuel and services provider. AREVA provides experience in vessel and internals segmentation, with specific BWR experience. AREVA successfully disassembled the reactor pressure vessel at the Wuergassen nuclear power station in Germany. AREVA also has D&D experience at decommissioning of NRC regulated power reactors, including reactor pressure vessel and internals segmentation and packaging at Yankee Rowe, Maine Yankee, and the Connecticut Yankee nuclear power plants. In addition, AREVA has experience working on decommissioning projects in several countries in Europe as well as in Japan. Orano is expected to provide these types of services to the VY decommissioning project.

Burns & McDonnell is an engineering, architecture, construction, environmental and consulting firm that will provide engineering and license termination support to the project. Burns & McDonnell experience includes decommissioning of the NRC licensed Kerr McGee/TRONOX nuclear fuel plant in Oklahoma. In addition, through a joint venture, Burns & McDonnell has prepared the final status survey reports for various buildings at the NRC licensed Mallinckrodt, Inc.'s St. Louis, Missouri site.

Waste Control Specialists, LLC (WCS) is a State of Texas regulated low-level radioactive waste management, packaging, transportation and disposal company. WCS would provide on-site waste processing, management, packaging and loading, as well as disposal in accordance with the requirements of the Texas Low-Level Waste Compact. The WCS Senior Management team includes personnel experienced in waste packaging and disposal, such as the Vice President of Operations, who has over 20 years of experience in the radioactive waste management industry and has worked at numerous DOE sites including the Pantex Plant, Rocky Flats Environmental Technology Site, Idaho Cleanup Project, and the Nevada Security Site.

By letter dated November 3, 2017 (ADAMS Accession Number ML17313A431), the staff requested additional information regarding the Applicants' previous experience with NRC regulated decommissioning projects and the experience of the senior management and other key management personnel to better determine the qualifications of those persons and for a description of the responsibilities for the management positions not identified with a specific person. Staff also requested additional information on how the current VY decommissioning organization would transition to the organization proposed by the Applicants, how individuals from NorthStar's strategic partners would fit into the planned NorthStar NDC organization. In addition, the Applicants were asked to describe the lines of communication and authority of the proposed new organization and for further information regarding NorthStar's management and technical role in decommissioning projects at NRC licensed sites including NorthStar's role as either the principal lead contractor or subcontractor and the technical services it provided.

In response, by letter dated December 4, 2017 (ADAMS Accession Number ML17339A896), the Applicants provided the additional information requested which included further detail on the responsibilities and experience of the senior managers, the proposed changes to the current technical organization that would result from the transfer, and identification of where NorthStar NDC and its strategic partners fit into the planned organization chart. However, clear information was not provided as to the relationship and responsibilities of NorthStar to the other contractors on previous decommissioning projects and their relationship with the licensee. Therefore, by letter dated April 5, 2018 (ADAMS Accession Number ML18045A817), the staff requested additional information on NorthStar's management and technical role in various decommissioning projects licensed by the NRC in order to better understand the NorthStar role versus the roles of the other contactors involved with those projects.

The Applicant's RAI response dated May 21, 2018, (ADAMS Accession Number ML18142B193) better defined the regulatory and technical roles of NorthStar on previous projects involving NRC research reactor licensees and their relationship with the licensees. The response specifically described NorthStar's direct involvement and oversight of subcontractors that provided health physics support, radiation surveys, and supported waste packaging, transportation, and disposal. The response also described how NorthStar managed the projects and directly performed planning, dismantlement, decontamination, waste packaging, facility demolition, and site restoration. In addition, the response also provided the experience of the identified Director of Health Physics and Waste Operations against the requirements of ANSI/ANS-3.1-2014 "Selection, Qualification, and Training of Personnel for Nuclear Power Plants," (Section 4.3.3, Radiation Protection). While NorthStar NDC Director of Health Physics and Waste Operations is not required to fulfill the ANSI/ANS-3.1-2014 criteria, the Applicants stated that the proposed NorthStar NDC Director of Health Physics and Waste Operations has the education, training, and experience to fulfill the requirements of ANSI/ANS-3.1-2014.
The application and the supplemental information provided through NorthStar's response to the RAIs provided the staff with an adequate understanding of NorthStar's previous decommissioning experience at NRC licensed sites, the organizational and reporting structure of the proposed NorthStar NDC organization, the responsibilities of NorthStar's strategic partners in the project and NorthStar's qualifications to undertake the VY decommissioning project.

Conclusion

Based on its review of the application for license transfer and supplemental information submitted in response to the RAIs, the NRC staff finds that the Applicants provided reasonable assurance that the requirements of 10 CFR 50.34(a)(9) and 10 CFR 50.80 regarding the technical qualifications of NorthStar NDC to engage in the proposed activities have been met. In addition the staff finds that NorthStar NDC is technically qualified to be the holder of the license, and that the transfer of the license is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission. Accordingly, the staff concludes that the proposed NorthStar NDC management and technical support organization will adequately support the proposed maintenance and decommissioning activities at VY.

9.2 Onsite Organization

The NRC staff reviewed the application and supplemental information provided in response to the RAIs to determine the acceptability of the onsite organization at VY regarding the

organizational structure for accountability and reporting, and to evaluate any changes to the organization proposed as a result of the license transfer. VY's operating organization was determined to be acceptable by the initial licensing review and subsequent safety-related changes to the operating organization have been evaluated and approved by the NRC. The NRC staff determined that the proposed NorthStar NDC organization that would be responsible for the maintenance and decommissioning of the VY facilities, including the ISFSI, will reflect the current Entergy decommissioning organization, and would be adequate to perform decommissioning and spent fuel management at VY.

Conclusion

Based on its evaluation, the NRC staff concludes that the onsite organization will adequately support the proposed maintenance and decommissioning activities at VY in accordance with 10 CFR 50.34(a)(9) that requires applicants to provide the technical qualifications to engage in the proposed activities, and 10 CFR 50.80(c) that requires the proposed license transferee to be qualified to be the holder of the license and is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission.

9.3 Technical Qualifications Conclusions

The Applicants have described the management and technical support organization, as well as the onsite operating organization, that would be responsible for the maintenance and decommissioning of VY after the proposed transfer of licensed authority to NorthStar NDC. Based on its evaluation as described above, the staff concludes that: (1) NorthStar NDC will have an acceptable management organization; (2) NorthStar NDC will retain an onsite organization capable of safely conducting decommissioning activities; and (3) NorthStar NDC will have the technically qualified resources and experience to support the safe maintenance and decommissioning of the VY site after the transfer of licensed authority from ENOI to NorthStar NDC. The NRC staff also determined that the Applicants provided reasonable assurance that the relevant requirements of 10 CFR 50.34(a)(9) and 10 CFR 50.80 to engage in the proposed activities have been met. Accordingly, in light of the foregoing evaluation, the NRC staff finds that NorthStar NDC is technically qualified to hold the VY License No. DPR-28 as proposed.

10.0 CONFORMING LICENSE AMENDMENT

10.1 Conforming Amendment

The applicants requested a conforming amendment to License No. DPR-28 for VY. No physical or operational changes to the facility were requested beyond those captured in the VY PSDAR. The proposed conforming amendment only reflects the proposed license transfer action. The amendment involves no safety question and is administrative in nature. Accordingly, the proposed amendment is acceptable.

10.2 State Consultation

In accordance with the Commission's regulations, the Vermont State official was notified of the proposed issuance of the amendment on October 4, 2018. The State official did not provide any comments.

10.3 Conforming Amendment Conclusion

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by the proposed action; (2) there is reasonable assurance that such activities will be conducted in compliance with the Commission's regulations; and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

11.0 ENVIRONMENTAL CONSIDERATION

The subject application is for approval of a transfer of a license issued by the NRC and an associated conforming amendment required to reflect the approval of the transfer. Accordingly, the actions involved meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(21). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the approval of the transfer application and conforming license amendment.

12.0 PUBLIC COMMENT

The NRC's notice of consideration of the approval of transfer of license and conforming amendment was published in the Federal Register on May 24, 2017 (82 FR 23845). The notice included an opportunity to provide written comment and notice that NRC was participating in a public meeting of the Vermont Nuclear Decommissioning Citizens Advisory Panel (NDCAP) on May 25, 2017. The announcement also identified that NRC personnel at the public meeting would take oral or written comments on the application for the proposed license transfer and the associated proposed revised updated PSDAR. A summary of the oral comments are captured in the public meeting summary (ADAMS Accession No. ML17192A375), a transcript of the public meeting is at ADAMS Accession No. ML17163A424.

In addition, five written comments were received in response to the Federal Register notice. These comments can be found at ADAMS Accession Numbers ML17163A087, ML17163A088, ML17179A245, ML17179A246, and ML17180A320.

There were several questions and comments from both the NDCAP and the general public at the meeting. The themes of the written questions and comments overlapped with the oral questions and comments. The themes of the questions and comments were as follows:

1) Concerns about the responsibility for any decommissioning fund shortfalls and the financial integrity or other qualifications of NorthStar and its partners

2) Use of the site after decommissioning

3) Concerns about continued storage of spent fuel after decommissioning, transportation of spent fuel and radioactive waste, and where spent fuel will go once removed from the site

4) Support for the timely review and approval of the license transfer and the immediate decommissioning of the facility

5) Concerns that support for the license transfer is partially based on proprietary information or incomplete cost information, and that the work will have proper oversight

6) Concerns about the proposal to rubbilize parts of the facility and burying it onsite and also support for that proposal

7) Concerns about the reduction of emergency planning and the proximity of school children to the plant site

8) Concern about Entergy's current use of the decommissioning trust fund

9) NRC communications and coordination on the review process

10) The potential impact on cultural resources and environmental justice issues from site decommissioning and waste disposal

The NRC staff reviewed the questions and comments made in the public meeting along with the written comments received during the open comment period and considered them in the review process. The themes of the questions and comments that were in the scope of the NRC's review, such as concerns about decommissioning fund shortfalls and the financial integrity and/or the financial and technical qualifications of NorthStar and its partners, are addressed in this safety evaluation of the license transfer request.

13.0 CONCLUSION

Based on the foregoing, and subject to the conditions described herein, the NRC staff concludes that NorthStar NDC and NorthStar VY are financially and technically qualified to hold the license for the Vermont Yankee Nuclear Power Station and the general license for the VY ISFSI, as described in the application, and engage in the proposed maintenance and decommissioning activities associated with the VY site. The NRC staff has concluded, based on the considerations discussed above, that: (1) the proposed transferees are qualified to be the direct and indirect holders of license DPR-28 and (2) the direct and indirect transfer of the license is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission pursuant thereto.

Additionally, the NRC staff finds that the Applicants have satisfied the NRC's decommissioning funding assurance requirements and the applicable onsite and offsite insurance requirements as conditioned. Further the NRC staff finds that the Applicants are not owned, controlled, or dominated by a foreign entity.

Principal Contributors: M. Henderson, NRR/DIRS
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J. Parrott, NMSS/DUWP

Date: October 11, 2018

VERMONT YANKEE LICENSE TRANSFER

All expenses with additional future funds collections. *In Thousands of constant 2016 $*

NORTHSTAR TRANSFER APPLICATION & PSDAR (reflecting data from May 21, 2018 RAI response)

YEAR	10 CFR 50.75 TRUST OPENNING BALANCE		SUPPLEMENTAL DECOMMISSIONING FUNDS	[AS ASSUMED] DOE REIMBURSEMENT SFM COLLECTED	NRC LICENSE TERMINATION	SPENT FUEL MANAGEMENT	SITE RESTORATION <E]	ISFSI DECOMMISSIONING	2.00% REAL RATE OF RETURN	TRUST CLOSING BALANCE
2016										
2017										
2018										
2019	$488,000	[A>	$30,000		$66,672	$9,241	$0		$8,842	$450,929
2020	$450,929				$65,612	$6,141	$0		$7,584	$386,759
2021	$386,759				$69,745	$4,241	$0		$6,255	$319,029
2022	$319,029				$78,438	$4,241	$0		$4,727	$241,077
2023	$241,077				$87,519	$4,241	$0		$2,986	$152,303
2024	$152,303				$76,253	$4,241	$0		$1,436	$73,245
2025	$73,245	[C>		$20,000	$41,369	$8,657	$0		$864	$44,084
2026	$44,084				$9,390	$5,104	$0		$592	$30,181
2027	$30,181	[B>	$140,000		$0	$9,275	$0		$3,218	$164,125
2028	$164,125			$20,000	$0	$9,275	$0		$3,497	$178,347
2029	$178,347				$0	$9,275	$0		$3,381	$172,453
2030	$172,453				$0	$9,275	$0		$3,264	$166,442
2031	$166,442			$20,000	$0	$9,275	$0		$3,543	$180,710
2032	$180,710				$0	$9,275	$0		$3,429	$174,864
2033	$174,864				$0	$9,275	$0		$3,312	$168,900
2034	$168,900			$20,000	$0	$9,275	$0		$3,593	$183,218
2035	$183,218				$0	$9,275	$0		$3,479	$177,422
2036	$177,422				$0	$9,275	$0		$3,363	$171,510
2037	$171,510			$20,000	$0	$9,275	$0		$3,645	$185,879
2038	$185,879				$0	$9,275	$0		$3,532	$180,136
2039	$180,136				$0	$9,275	$0		$3,417	$174,279
2040	$174,279			$20,000	$0	$9,275	$0		$3,700	$188,704
2041	$188,704				$0	$9,275	$0		$3,589	$183,017
2042	$183,017				$0	$9,275	$0		$3,475	$177,217
2043	$177,217			$20,000	$0	$9,275	$0		$3,759	$191,701
2044	$191,701				$0	$9,275	$0		$3,649	$186,074
2045	$186,074				$0	$9,275	$0		$3,536	$180,335
2046	$180,335			$20,000	$0	$9,275	$0		$3,821	$194,882
2047	$194,882				$0	$9,275	$0		$3,712	$189,319
2048	$189,319				$0	$9,275	$0		$3,601	$183,645
2049	$183,645			$20,000	$0	$9,275	$0		$3,887	$198,257
2050	$198,257				$0	$9,275	$0		$3,780	$192,762
2051	$192,762				$0	$9,275	$0		$3,670	$187,156
2052	$187,156	[D>		$20,000	$0	$9,807	$0	$3,454	$3,878	**$197,773**
TOTAL EXPS>					$494,998	$287,789	$0	$3,454		
						GRAND TOTAL EXPENSES>		$786,241		

NOTES:
[A> $30 million potential use of escrow account & it is included for escrow growth
[B> $140 million is support agreement (originally $125 million)
[C> $20 million revolving DOE reimbursement assuming six year process for first installment
[D> Trust closing balance must be positive to provide reasonable assurance
[E> Site restorarion via separate $25 million trust

DOE/RW-0596

Report to Congress on the Demonstration of the Interim Storage of Spent Nuclear Fuel from Decommissioned Nuclear Power Reactor Sites

December 2008

U.S. Department of Energy
Office of Civilian Radioactive Waste Management
Washington, D.C.

The picture on the cover is the Connecticut Yankee Independent Spent Fuel Storage Installation site in Haddam, Connecticut, with 43 dry storage NRC-licensed dual-purpose (storage and transport) casks.

EXECUTIVE SUMMARY

The House Appropriations Committee Print that accompanied the Consolidated Appropriations Act, 2008, requests that the U.S. Department of Energy (the Department):

> …develop a plan to take custody of spent fuel currently stored at decommissioned reactor sites to both reduce costs that are ultimately borne by the taxpayer and demonstrate that DOE can move forward in the near-term with at least some element of nuclear waste policy. The Department should consider consolidation of the spent fuel from decommissioned reactors either at an existing federal site, at one or more existing operating reactor sites, or at a competitively-selected interim storage site. The Department should engage the 11 sites that volunteered to host Global Nuclear Energy Partnership facilities as part of this competitive process.

The Department has reviewed its authority to accept spent nuclear fuel from decommissioned commercial nuclear power reactor sites for interim storage and has concluded that it has no such currently exercisable authority. Legislation is required that would eliminate the limitations in the Nuclear Waste Policy Act of 1982, as amended, on taking commercial spent nuclear fuel for interim storage prior to the opening of the Yucca Mountain repository. In addition, in order to undertake interim storage in a timely manner, legislation would be needed: (1) to direct the Department to take spent nuclear fuel from decommissioned commercial nuclear power reactors as soon as possible; (2) to establish an expedited siting process; and (3) to authorize the Department to construct and operate the facility under its regulatory authority, or, if the facility were to be constructed and operated under a U.S. Nuclear Regulatory Commission license, to provide for an expedited siting and licensing process. Furthermore, such legislation should also provide for funding reform to ensure that the Department would have access each year to adequate funds from the Nuclear Waste Fund to carry out such activities. Reliable and sufficient funding is necessary for the simultaneous development of the Yucca Mountain repository, an interim storage facility, and transportation of spent nuclear fuel to both facilities.

The Department has concluded that, without legislation, a demonstration could not be completed in the near term and would not reduce taxpayer costs for waste disposal. Assuming expeditious resolution of a number of complex statutory, regulatory, siting, construction, and financial issues, if development were to begin in 2009, such a facility might begin operations in 2015 at the earliest and complete operations by shipping commercial spent nuclear fuel from the interim storage facility to Yucca Mountain between 2025 to 2028 at a cost of $743 million. It would increase the total system life cycle costs of the repository program under the Nuclear Waste Policy Act of 1982, as amended.

The ongoing liability associated with the Department’s delay in waste acceptance (currently $11 billion, assuming that operation of the Yucca Mountain repository begins in 2020) would not be reduced in any significant way and could be increased if directing the priority acceptance of spent nuclear fuel from the ten decommissioned commercial nuclear power reactors resulted in additional litigation from contract holders with operating reactors. If Congress authorizes the Department to initiate interim storage for the consolidation of the spent nuclear fuel from decommissioned commercial nuclear power reactors and amends the interim storage siting provisions provided in the Nuclear Waste Policy Act of 1982, as amended, the Department

would consider either an existing federal site, one or more existing operating commercial nuclear power reactors, or a competitively selected interim storage site, engaging the sites that have volunteered to host Global Nuclear Energy Partnership facilities as part of the competitive process.

Authorization and funding by Congress to perform interim storage would provide the Department an option in addition to Yucca Mountain to allow the Department to begin to meet its contractual obligations with the owners of commercial spent nuclear fuel. This option could prove beneficial should Yucca Mountain experience delays due to licensing, litigation, lack of funding, or other causes, but only if the enabling legislation adequately addresses the issues discussed in this report.

CONTENTS

TABLES

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ACRONYMS

AEA	Atomic Energy Act
DOE	U.S. Department of Energy
GNEP	Global Nuclear Energy Partnership
HLW	high-level radioactive waste
MRS	monitored retrievable storage
MTHM	metric tons of heavy metal
NRC	U.S. Nuclear Regulatory Commission
NWF	Nuclear Waste Fund
NWPA	Nuclear Waste Policy Act
OFF	oldest fuel first
SNF	spent nuclear fuel

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1. INTRODUCTION

This report has been produced at the request of Congress. The House Appropriations Committee Print that accompanied the Consolidated Appropriations Act, 2008, requests that the U.S. Department of Energy (the Department):

> …develop a plan to take custody of spent fuel currently stored at decommissioned reactor sites to both reduce costs that are ultimately borne by the taxpayer and demonstrate that DOE can move forward in the near term with at least some element of nuclear waste policy. The Department should consider consolidation of the spent fuel from decommissioned reactors either at an existing federal site, at one or more existing operating reactor sites, or at a competitively-selected interim storage site. The Department should engage the 11 sites that volunteered to host Global Nuclear Energy Partnership facilities as part of this competitive process.

This report discusses the status of the commercial spent nuclear fuel (SNF) inventory in the United States, at both decommissioned and operating commercial nuclear power reactor sites; summarizes the contractual arrangement the government and utilities have under the Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (10 CFR Part 961) (Standard Contract), related litigation, and the financial liabilities resulting from the Department's delay in performance under these contracts; provides a history of interim storage policy as it relates to commercial SNF in the United States; and identifies actions that would be necessary for the Department to develop an interim storage facility and demonstration program for commercial SNF from the decommissioned commercial nuclear power reactor sites.

2. CURRENT COMMERCIAL SNF STORAGE

There are currently 104 operating and 14 permanently shutdown commercial nuclear power reactors in the United States; four of these shutdown reactors are located at sites with other operating reactors. The other ten shutdown reactors are located at nine sites with no other nuclear operations.

For purposes of this report, the Department interprets the Congressional intent in the House Appropriations Committee Print to be the ten shutdown (decommissioned) commercial nuclear power reactors located at the nine sites with no other nuclear operations.

The SNF stored at the nine sites represents a small portion of the total SNF inventory currently stored at 72 commercial sites in the United States. An interim storage facility developed solely for the SNF from the nine sites would be significantly smaller than storage facilities previously considered as part of the federal waste management system.

2.1 COMMERCIAL SNF AT DECOMMISSIONED NUCLEAR POWER REACTOR SITES

There are currently ten decommissioned commercial nuclear power reactors located at nine sites with no other nuclear operations. Approximately 2,800 metric tons of heavy metal (MTHM) of SNF is stored on a temporary basis at these nine sites, awaiting removal by the Department for

permanent disposal. Until this SNF is removed from these nine sites, the sites cannot be fully decommissioned and made available for other purposes.

As of the end of 2007, six of the nine sites have developed independent spent fuel storage installations and placed all of their SNF into dual-purpose storage systems; one additional site is loading its SNF into dry storage during 2008. While the two remaining sites are planning for dry storage, the facilities have not yet been developed, and over 1,000 MTHM of SNF remains in pool storage at these two sites. Table 1 provides a summary of the nine sites, including the quantity and status of the SNF located at the sites. For the sites that have not yet implemented dry cask storage, one has already entered into a contract for dry storage, and for the other, the Department has estimated the number of storage casks.

As noted in Table 1, the Department estimates that all of the SNF currently located at the nine sites will be packaged in approximately 294 storage/transport cask systems. These systems utilize a sealed stainless steel canister to contain the SNF. The SNF canister and the required overpacks will be certified by the U.S. Nuclear Regulatory Commission (NRC) for storage (under 10 CFR Part 72) and transportation (under 10 CFR Part 71). These canisters, when placed in an approved transportation overpack, can be shipped directly from the utility site to an interim storage facility, where the canister would be taken from the transportation overpack and placed into a storage overpack for interim storage.

Table 1. Status of Decommissioned Commercial Nuclear Power Reactor Sites in the U.S.

Plant	State	MTHM Stored at Site	MTHM in Pool Storage	MTHM in Dry Storage	Number of Casks	DOE Estimated Casks	Total Casks (Actual Plus Estimated)	Average MTHM/Cask
Big Rock Point	Michigan	58	0	58	7	—	7	8.3
Haddam Neck	Connecticut	412	0	412	41	—	41	10.1
Humboldt Bay[a]	California	29	0	29	5	—	5	5.8
LaCrosse[b]	Wisconsin	38	38	0	5	—	5	7.6
Maine Yankee	Maine	542	0	542	60	—	60	9.0
Rancho Seco	California	228	0	228	21	—	21	10.9
Trojan	Oregon	359	0	359	34	—	34	10.6
Yankee Rowe	Massachusetts	127	0	127	15	—	15	8.5
Zion 1 & 2[c]	Illinois	1,019	1,019	0	—	106	106	9.6
TOTALS		2,813*	1,057	1,756*	188	106	294	—

NOTE: [a]Dry storage underway in 2008. Holtec canister has capacity of 80 assemblies (five canisters for the 390 assemblies).

[b]Dry storage contract entered with NAC for five NAC-MPC canisters. Dry storage schedule indicates target completion by the end of 2010.

[c]Decommissioning contract entered with EnergySolutions. Canisters estimated using FuelSolutions W21 capacity. Target schedule for completion is 2013.

DOE = U.S. Department of Energy; MPC = multipurpose canister; NAC = Nuclear Assurance Corporation.

*Totals might differ from sums of values due to rounding.

3. STANDARD DISPOSAL CONTRACTS, LITIGATION, AND FINANCIAL LIABILITIES

The Standard Contract (10 CFR Part 961) defines the terms and conditions under which the government will accept commercial SNF for disposal in a geologic repository. The Department has taken the position that, as a general matter with respect to existing reactors, it will implement the Standard Contract by taking commercial SNF in the order it was generated. If Congress enacted legislation that directed the Department to take SNF from decommissioned reactors as a limited demonstration program, the Department would assign a priority to the acceptance of the SNF from these sites, pursuant to the provision in the Standard Contract that grants the Department the discretion to take SNF from decommissioned reactors on a priority basis. As discussed in the following sections, this situation would be a change from the current Department position stated previously.

3.1 STANDARD DISPOSAL CONTRACT

Section 302(a) of the Nuclear Waste Policy Act of 1982, as amended (NWPA), authorizes the Secretary of Energy to "enter into contracts with any person who generates or holds title to high-level radioactive waste, or spent nuclear fuel." These contracts cover the acceptance of title, subsequent transportation, and disposal of such high-level radioactive waste (HLW) or SNF. The NWPA stipulates that the contracts provide for the payment of fees to the Secretary to offset the expenditures of providing these services, and specifically in Section 302(a)(5), it further requires that contracts entered into under this section provide that:

A. **following commencement of operation of a repository [**emphasis added**]**, the Secretary shall take title to the high-level radioactive waste or spent nuclear fuel involved as expeditiously as practicable upon the request of the generator or owner of such waste or spent fuel; and

B. in return for the payment of fees established by this section, the Secretary, beginning not later than January 31, 1998, will dispose of the high-level radioactive waste or spent nuclear fuel involved as provided in this subtitle.

In 1983, the Department promulgated the provisions in a disposal contract through notice and comment rulemaking. The resulting contract, known as the Standard Contract, can be found at 10 CFR 961.11.

Priority for Waste Acceptance—In addition to the provisions required by the NWPA, the Standard Contract also contains provisions that establish the responsibilities of the parties, the terms for payment, and the processes and procedures for the transfer of title and physical possession of the HLW and SNF from the utility company to the federal government. In particular, the Standard Contract establishes the process for allocating the federal government's finite waste acceptance capacity among the various utility purchasers.

This waste acceptance allocation, also known as the acceptance queue, is developed in accordance with the principle of "oldest fuel first" (OFF). Under the OFF methodology, the oldest SNF, as measured from the date of permanent discharge from the reactor, is given the highest priority in the acceptance queue. This approach ensures that all SNF, regardless of

location or ownership, is afforded equal treatment in establishing waste acceptance priority. Using the OFF methodology to allocate the Department's planned waste acceptance capacity, the last SNF shipment from the ten decommissioned commercial nuclear power reactors considered in this report would be 15 years after the repository begins operations.

The contract allows the OFF queue to be altered under certain conditions with Department consent. For instance, utility companies may, subject to Department approval, exchange places in the waste acceptance queue. Additionally, the Department may alter the queue by granting priority acceptance in cases of emergencies or by permitting priority acceptance of the SNF from reactors that have permanently ceased operations (decommissioned reactors).

The Department has been asked, on numerous occasions, to exercise its discretion under the Standard Contract to allow for the priority acceptance of SNF from decommissioned reactors. In all instances, the Department has declined to grant this priority, noting that doing so would, because of the finite nature of the federal government's planned waste acceptance capacity, adversely affect the timely removal of SNF from operating reactor sites. In other words, acceleration in waste acceptance from a decommissioned reactor site would result in a corresponding delay in removing SNF from an operating reactor site. Because of issues of equity that may result from this reallocation of waste acceptance capacity, the government has consistently advised the parties seeking such priority treatment to avail themselves of the exchange provisions of the Standard Contract that allow the utilities to exchange approved delivery commitments subject to the Department's approval.

3.2 CURRENT LITIGATION RELATED TO THE STANDARD CONTRACT

Because the Department has had no facility available to receive SNF under the NWPA, it has been unable to begin accepting SNF as required by the Standard Contracts. Significant litigation has ensued as a result of this delay. The Federal Circuit Court in the cases Northern States Power Co. v. U.S., 224 F.3d 1361 (Fed. Cir. 2000) and Maine Yankee Atomic Power Company v. United States, 225 F.3d 1336 (Fed. Cir. 2000) found the Department to be in partial breach of its contracts and found that utilities are entitled to recover damages for that breach. To date, more than 70 lawsuits have been filed, and more than 50 lawsuits remain pending against the government for delay damages.

Between 1998 and 2004, all ten decommissioned reactor utilities filed cases against the government for its delay. Claims for two of the decommissioned reactor utilities have been settled, and claims for the other eight decommissioned reactor utilities remain pending either in the U.S. Court of Federal Claims (trial courts) or in the U.S. Court of Appeals for Federal Circuit (appellate court). The government has appealed trial court damage awards of approximately $226 million for five decommissioned reactors, but no final rulings have been issued in those cases.

3.3 FINANCIAL LIABILITIES DUE TO DELAY IN WASTE ACCEPTANCE

The government has settled claims with utilities covering 29 of the 118 operating and decommissioned reactors, nearly 25 percent of the commercial nuclear power reactors covered by Standard Contracts. If the Department begins to accept SNF by 2020, the Department

estimates that the federal government's liability for delay damages may be up to approximately $11 billion. For each additional year of delay, the Department estimates that there may be hundreds of millions of dollars of additional damages.

As discussed in Section 2.1, seven of the nine decommissioned nuclear power reactor sites have already constructed interim storage facilities at the reactor sites and deployed dry cask storage systems for their entire SNF inventory. In most cases the government will be responsible for a portion of the costs incurred at these sites due to the Department's failure to begin accepting SNF in 1998, and those costs will be paid from the Judgment Fund. Accepting SNF from decommissioned reactors is unlikely to have any effect on the amount of damages unless the legislation that established the limited demonstration program was to make the elimination or reduction of damages a condition of participation.

Because most of the ten decommissioned reactors have already incurred costs for their onsite storage facilities, a limited demonstration program to remove the SNF from these sites to an interim storage facility would not significantly change the estimated overall liability of $11 billion. At the same time, directing the priority acceptance of SNF from the ten decommissioned reactors would likely result in additional litigation from contract holders with operating reactors, as well as in demands for acceptance of their SNF at an interim storage facility.

4. HISTORY OF INTERIM STORAGE POLICY IN THE U.S.

This section provides a review of the history of interim storage policy to date. The Department has under certain circumstances accepted commercial SNF under the authority of the Atomic Energy Act of 1954 (AEA) (42 U.S.C. 2011 et seq.). The NWPA, however, severely limits the Department's authority to accept such SNF for interim storage.

4.1 DOE AUTHORITY TO ACCEPT SNF UNDER THE ATOMIC ENERGY ACT OF 1954

Prior to the enactment of the NWPA in 1982, the Department had authority and continues to have authority to accept SNF in certain circumstances pursuant to the AEA. Section 55 of the AEA, as amended (42 U.S.C. 2075), provides that the Department "is authorized, to the extent it deems necessary to effectuate the provisions of [the Act], to purchase, … take, requisition, condemn, or otherwise acquire any special nuclear material or any interest therein." The authority under the AEA may be exercised to further any of its purposes, including international cooperation and nuclear nonproliferation, support of research and development in nuclear power, and management of the U.S. nuclear defense programs (42 U.S.C. 2111, 42 U.S.C. 2112, 42 U.S.C. 2013, 42 U.S.C. 2051(a), and 42 U.S.C. 2152).

Pursuant to this AEA authority, the Department has accepted and stored U.S.-supplied foreign reactor fuel at various DOE sites. The Department has also used this authority to accept small amounts of SNF for research and development purposes, such as parts of the Three Mile Island Unit 2 damaged reactor core and other damaged SNF. The Department has also accepted commercial SNF under settlement of disputes resulting from contracts that predate enactment of the NWPA.

However, the later-enacted NWPA provided a detailed statutory scheme for SNF storage and disposal and limited the Department's authority to accept SNF under the AEA except in compelling circumstances such as acceptance of SNF to abate a public health risk in an emergency. For the Department to accept any commercial SNF under the AEA, the Department could do so only under certain circumstances determined to be identifiable exceptions in the AEA like those discussed previously. In the absence of statutory direction to accept SNF from decommissioned reactors that explicitly addressed the limitations imposed by the NWPA, the Department does not believe that the acceptance of the SNF from the ten decommissioned reactors considered in this report would be permitted under an identifiable exception in the AEA.

4.2 DOE AUTHORITY UNDER THE NUCLEAR WASTE POLICY ACT OF 1982

With enactment of the NWPA, Congress provided a detailed statutory scheme for commercial SNF storage and disposal that, by its specificity, limits the Department's commercial SNF storage and disposal options as follows.

The NWPA permits the Department to undertake interim storage in two distinct instances, descriptions of which follow, neither of which can currently be exercised.

First, Section 135 of the NWPA (Subtitle B—Interim Storage Program) authorized the Department to enter into contracts to assist or provide temporary storage, known as federal interim storage, for a limited amount of SNF under certain specified conditions (including a separate fee) until a repository was available. This authority expired in 1990.

Second, Section 141 of the NWPA (Subtitle C, Monitored Retrievable Storage), authorized the Department to site, construct, and operate a monitored retrievable storage (MRS) facility but restricted the ability of the Department to pursue this option by linking any activity under this section to milestones tied to progress in the development of the Yucca Mountain repository (42 U.S.C. 10155 to 42 U.S.C. 10157). For example, before the MRS can be constructed, the NRC must have issued a construction authorization for the Yucca Mountain repository; and until the Yucca Mountain repository starts accepting SNF, the quantity of SNF stored at the MRS site cannot exceed 10,000 MTHM. After the Yucca Mountain repository starts accepting SNF, the total quantity of SNF at the MRS site cannot exceed 15,000 MTHM at any one time. Additionally, the NWPA stipulated that the MRS cannot be located in the State of Nevada.

In 1994, in an effort to consider all available avenues to accept commercial SNF, the Department issued a Notice of Inquiry on Waste Acceptance Issues seeking public comment on, among other issues, whether the Department had statutory authority under the NWPA to provide interim storage of SNF (59 FR 27007). In the subsequent 1995 final report responding to public comments, the Department determined again that the NWPA explicitly contemplated interim storage in only two instances: interim storage under Section 135 of the NWPA and an MRS under Section 141 of the NWPA (Office of Civilian Radioactive Waste Management; Nuclear Waste Acceptance Issues, 60 FR 21793). However, the report also noted that *the interim storage provision had expired and the MRS provisions were unusable because of the required linkages to repository development*. The report concluded that because neither of the NWPA's explicit interim storage authorities applied and because the NWPA precluded the Secretary from spending Nuclear Waste Fund (NWF) monies for construction or expansion of a facility without

express authorization from Congress, the Department lacked authority at that time to provide interim storage under existing law. Specifically, the report stated the following:

> Interim storage by DOE was contemplated by the Act in only two situations, neither of which currently applies. Under the Act, DOE had authority to offer a limited interim storage option. See 42 U.S.C. 10156. However, that authority has, by its express terms, expired. Under the Act, DOE also has the authority to provide for interim storage in an MRS. That authority also is inapplicable, however, because the Act ties construction of an MRS to the schedule for development of a repository. See 42 U.S.C. 10165, 10168. Because these are the only interim storage authorities provided by the Act, and because the Act expressly forbids use of the Nuclear Waste Fund to construct or expand any facility without express congressional authorization (42 U.S.C. 10222(d)), *DOE lacks authority under the Act to provide interim storage services under present circumstances*. (60 FR 21793; emphasis added)

In addition, whether or not the Department can begin accepting SNF from commercial utilities prior to receiving construction authorization for the Yucca Mountain repository has been one of the issues litigated by contract holders. No court has found that the Department has authority under the NWPA to accept SNF from commercial utilities at this time.

For these reasons, the Department believes that any statutory direction to begin accepting SNF from decommissioned reactors would also need to address the limitations on the current exercise by the Department of its authority under the AEA to accept commercial SNF, as discussed earlier in this section.

5. PREREQUISITES FOR A LIMITED DEMONSTRATION OF INTERIM STORAGE OF SNF FROM NINE DECOMMISSIONED NUCLEAR POWER REACTOR SITES

The Department has identified a number of issues that would need to be addressed in any legislation that would direct the Department to begin accepting SNF from decommissioned reactors in order for the Department to have the ability to implement such direction in a timely and efficient manner. As noted previously, the limitations in the NWPA on the current exercise by the Department of its authority under the AEA to accept commercial SNF would need to be rendered inapplicable to SNF from decommissioned reactors. In addition, the Department has concluded that the existing provisions in the NWPA relating to interim storage would not result in the timely and efficient implementation of statutory direction to begin accepting SNF from decommissioned reactors because of the length of time and the potential of the state to veto the site under the existing provision of the NWPA. To proceed in a timely manner, the Department would require legislation to (1) direct the Department to take SNF from decommissioned reactors as soon as possible under its AEA authority; (2) establish an expedited siting process; and (3) authorize the Department to construct and operate the facility under its own regulatory authority, or, if the facility were to be constructed and operated under an NRC license, to provide for an expedited licensing process. Moreover, to be effective, any legislation would need to include funding reform to ensure that the Department has prompt access to the annual fees and interest paid into the NWF so that the Department could undertake its obligations to construct both the interim storage facility and the Yucca Mountain repository in a timely and efficient manner and thereby fulfill its commitments to all contract holders.

5.1 AUTHORITY

Because of the limitations on the current exercise of the Department's authority under the AEA, any legislation would need to make those limitations inapplicable to SNF from decommissioned commercial nuclear power reactors. In addition, to minimize the potential for further litigation from other contract holders, the legislation would likely need to expressly direct the Department to exercise its discretionary authority under the Standard Contract to take SNF from the decommissioned reactors on a priority basis as part of a statutorily mandated limited demonstration program.

5.2 SITING PROCESS

The Department has concluded that timely and efficient implementation of a limited demonstration program would also require establishment of a new statutorily mandated expedited siting process, rather than use of the existing siting processes in Subtitles B and C of the NWPA.

5.2.1 Existing Interim Storage Siting Requirements under the NWPA

Under Subtitle B, Interim Storage Program, the Department was authorized to (1) assist or provide temporary interim storage at government facilities, (2) provide for the acquisition of temporary storage casks for federal or civilian nuclear sites, or (3) construct storage capacity at any civilian nuclear power site. This subtitle expired in 1990.

Under Subtitle C, Monitored Retrievable Storage, the Department is authorized to site, design, and license a storage facility. The Department cannot construct the facility, however, until the Department has received a construction authorization from the NRC for the Yucca Mountain repository. In addition, Section 145 of the Act also prohibits the Secretary from selecting a site that is located in the State of Nevada. The MRS Commission was established pursuant to Section 143 of the NWPA and delivered its report to Congress in 1989. The Department recommended the Yucca Mountain site for the development of a repository in 2002. The Department could proceed with the siting of an interim storage facility in accordance with the requirements of Sections 144 through 146 of the NWPA. Section 144 requires the Secretary to survey and evaluate potentially suitable sites. From a technical standpoint, such a facility could be successfully developed virtually anywhere in the nation, other than Nevada; however, as specifically stated in Section 144, the NWPA limits the Secretary's consideration stating that the Secretary shall consider the extent to which siting an MRS facility would:

1. Enhance the reliability and flexibility of the system for the disposal of spent nuclear fuel and high-level radioactive waste established under this Act;

2. Minimize the impacts of transportation and handling of such fuel and waste;

3. Provide for public confidence in the ability of such system to safely dispose of the fuel and waste;

4. Impose minimal adverse effects on the local economy and the local environment;

5. Provide a high probability that the facility will meet applicable environmental, health, and safety requirements in a timely fashion;

6. Provide such other benefits to the system for the disposal of spent nuclear fuel and high-level radioactive waste as the Secretary deems appropriate; and

7. Unduly burden a State in which significant volumes of high-level radioactive waste resulting from atomic energy defense activities are stored.

Upon completion of the site surveys, the Secretary can select a site in accordance with the provisions of Section 145 of the NWPA. The Secretary may select a site from the sites evaluated under Section 144 that the Secretary determines on the basis of available information to be the most suitable for the development of an interim storage facility that is an integral part of the system for the disposal of SNF and HLW. The Secretary shall also prepare an environmental assessment with respect to such a selection and shall submit the environmental assessment to Congress at the time the site is selected.

Additionally, at least six months before selecting a site, the Secretary must notify the governor and legislature of the state in which the site is located (or the governing body of the affected Indian tribe where such site is located) of the potential selection and the basis for such selection. At least one public meeting must be held in the vicinity of the potential site to solicit input from interested parties. Section 145 also prohibits the Secretary from selecting a site that is located in the State of Nevada.

Once the Secretary notifies Congress of the selection of a site, the selection is effective at the end of 60 calendar days from the date of Congressional notification, unless the governor and state legislature (or the governing body of the affected Indian tribe if the site is located on a reservation) have submitted to Congress a notice of disapproval with respect to the site. If a notice of disapproval is received, the selection of the site is not effective unless Congress overrides the notice of disapproval as provided under Section 115(c) of the NWPA.

The NWPA also stipulates the amount of financial assistance (grants, technical assistance, and other financial assistance) that the Department can provide the host state of the interim storage facility. This amount includes benefit payments of $5 million per year prior to the start of storage facility operations and $10 million per year thereafter.

5.2.2 Possible Expedited Siting Process

The Department has concluded that in order to allow for the timely implementation of an interim storage facility, the siting process for the interim storage facility for the demonstration program, to a very large extent, would need to follow the process that would be utilized for siting a commercial away-from-reactor storage facility. That is, there should be (1) no special provisions that link the siting, construction, or operation to events related to the Yucca Mountain repository; (2) no provisions for Presidential or Congressional involvement in approval of the site; and (3) no provisions for a veto. In addition, the siting process would be facilitated if substantial benefit payments were potentially available to the host state.

5.2.3 POTENTIAL LOCATIONS

As requested by Congress, the Department has considered the consolidation of the SNF from decommissioned reactors at an existing federal site, at one or more existing operating reactor sites, or at a competitively selected interim storage site, including sites that volunteered to host Global Nuclear Energy Partnership (GNEP) facilities as part of this competitive process. It is likely that state or local governments at or around the host site would impose limitations on the interim storage facility, such as a capacity limit to prevent the site from future expansion beyond an agreed-upon capacity or a financial penalty if the SNF is left in place and not removed to the Yucca Mountain repository within a specified time period.

5.2.3.1 Existing Federal Site

An interim storage facility could be developed at a DOE site or at many other federal sites. The Department's sites at Savannah River, Hanford, and Idaho possess existing infrastructures, including security programs for SNF, operational and regulatory expertise, fully developed environmental baselines, and rail access that would facilitate acceptance. The Idaho National Engineering Laboratory site may present some unique issues due to prior agreements between the Department and the State of Idaho regarding the acceptance of commercial SNF.

5.2.3.2 One or More Existing Operating Reactor Sites

The Department could solicit expressions of interest for the consolidation of SNF from decommissioned reactors at one or more operating reactor sites. If an existing NRC-licensed site were chosen, it would be necessary to develop the interim storage facility under NRC licensing requirements. Under current NRC regulations, the reactor operators are licensed to possess quantities of SNF only as required to operate their reactors. Accepting SNF from decommissioned reactors at an operating reactor site would require a modification to the operating reactor's NRC license. This process may require hearings that could be contentious, thus delaying acceptance. Like the Department's sites, existing reactor sites have fully developed nuclear infrastructures and environmental baselines.

5.2.3.3 Competitively Selected Interim Storage Site

The Department could broadly solicit expressions of interest for the development an interim storage site for the SNF from the decommissioned reactors. This effort could build upon recent Department efforts in developing site characterization reports for eleven potential sites as part of the Department's GNEP program and other industry initiatives. As with the GNEP siting effort, the competitive process for selection of an interim storage facility should have the benefit of identifying a willing and supportive host. The sites may or may not have an existing nuclear infrastructure, and they could require more time for development and establishment of an environmental baseline. It should be noted, however, that local willingness and support for a site initially does not ensure continued support for the facility during the long timeframe needed to license and build such a facility.

5.3 LICENSING AND ENVIRONMENTAL REVIEW

Under Section 202 of the Energy Reorganization Act of 1972, any Department facility used primarily for the interim storage of commercial SNF must be licensed by the NRC. Information obtained from the NRC Web site indicates that the development of SNF storage facilities at nuclear power reactor sites typically takes up to three years from the decision to implement through operation.[1] The NRC review of the Private Fuel Storage license application for a proposed interim storage facility in Utah, which encountered significant public opposition, took over eight years. Since the SNF currently in storage at the nine decommissioned reactor sites is stored in six different types of storage systems, the license application for the interim storage facility would have to address the use of all these types of storage systems, and would be, therefore, more complex than the license application for existing facilities, which each use only one type of storage system.

Construction and operation of the interim storage facility would be expedited if the Department were authorized to use its authority under the AEA to regulate the facility. Alternatively, if the NRC were to license the facility, the NRC should be directed to use an expedited licensing process such as making use of the existing general license for certain interim SNF storage facilities. In addition, the NRC should be directed by statute to adopt DOE National Environmental Policy Act of 1969 (42 U.S.C. 4321) documents for the interim storage facility in a manner similar to the current approach in the NWPA, with respect to the environmental impact statement for the Yucca Mountain repository. Furthermore, as in the case for SNF that will be transported to the Yucca Mountain repository, the Department and not the NRC should be responsible for regulating the transportation of SNF to the interim storage facility.

5.4 CONSTRUCTION, TRANSPORTATION, AND OPERATIONS

Construction of the interim storage facility would be expedited if the interim storage facility were located at a site with existing nuclear infrastructure, rail transportation, and security services. At such a site, the required facilities would include a simplified canister receipt facility that could be utilized to remove the storage canisters from the transportation cask system and place them in appropriate onsite storage overpacks, an overpack fabrication facility for the onsite fabrication of the storage overpacks, an onsite transporter for transporting the loaded storage systems from the canister receipt facility to the storage pads, and one or more reinforced concrete storage pads. Based on experience at commercial nuclear facilities, the construction of these facilities could be completed in 12 to 24 months, assuming adequate funding, the issuance of all necessary permits, no linkage of construction to events related to the Yucca Mountain repository, and the absence of litigation-related delays.

Transportation—For the purpose of this report, the Department has developed an illustrative waste acceptance schedule for the acceptance of the SNF from the nine decommissioned reactor

[1] http://www.nrc.gov/waste/spent-fuel-storage/sf-storage-licensing/license-considerations.html

sites. To expedite acceptance in the near term, the Department has developed this schedule based on an approach that focuses on efficiency in transporting the SNF to the interim storage facility and does not follow the notification and scheduling requirements contained in the Standard Contracts. As shown in Table 2, the schedule presumes that all the SNF is removed from the nine decommissioned reactor sites in a period of four years.

Table 2. Waste Acceptance Schedule for the Acceptance of the SNF from the Nine Decommissioned Commercial Nuclear Power Reactor Sites

Shipping Schedule	MTHM	Shipments/Year
Year 1	400	46
Year 2	600	57
Year 3	794	85
Year 4	1,019	106
TOTAL	2,813	294

NOTE: The waste acceptance schedule does not consider technical attributes, such as the condition of the commercial SNF, that could affect the order and timing in which the Department could accept SNF for disposal.

SNF = spent nuclear fuel.

To implement transportation in accordance with this schedule, the Department would need to acquire more than 20 NRC-certified transportation casks and associated equipment, including rail rolling stock. While the number of casks required may appear high for such a small inventory of SNF, it is because the SNF at the seven decommissioned reactor sites with existing dry storage facilities is stored in six different types of SNF storage systems, each requiring a specific type of transportation cask system.

Operations—It is anticipated that the Department would store the SNF in NRC-approved storage systems in the same manner that the SNF is currently stored at the decommissioned reactor sites. As noted previously, this action would require the acquisition of six different types of storage systems and associated handling equipment. If the site is adjacent to an existing nuclear facility, utilization of the existing operational infrastructure would minimize cost and time before start-up.

5.5 FUNDING

5.5.1 Project Cost and Schedule

The Department has developed a preliminary cost estimate and schedule for the development and operation of an interim storage facility, if authorized by Congress, designed to accept and store the approximately 2,800 MTHM of SNF from the nine decommissioned reactor sites (Table 3). Table 3 shows that if successfully developed, under the assumptions discussed previously, such an interim storage facility could be developed to begin operations in 2015 at the earliest and to operate through 2028 at a cost of $743 million. The schedule and estimate assume that the site selected has a preexisting nuclear infrastructure, adequate funding, adequate rail access and an expedited site selection process with no opposition or litigation. Once accepted at the interim storage facility, the SNF would remain on site until it could be delivered to the Yucca Mountain repository without adversely impacting the acceptance of SNF from operating reactors.

Table 3. Estimated Cost and Schedule for Interim Storage of SNF from Decommissioned Nuclear Power Reactors Sites

Shutdown Storage Time Estimate	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Siting																				
NWPA Amendment																				
EIS																				
License Application																				
Licensing																				
Construction																				
Transportation	Plan	Acquire					Operations										Ship to Repository			
Storage Facility Operations																				

Shutdown Storage Cost Estimate	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Siting	$10																			$10
EIS/LA/ Licensing		$4	$6	$4	$4	$2	$0													$20
Storage Facility Construction				$4	$6	$10														$20
Storage Overpacks						$12	$19	$25	$32											$88
Transportation Equipment						$72	$72													$144
Transportation Operations							$12	$19	$25	$32							$29	$29	$29	$176
Storage Facility Operations							$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$130
Site Benefits NWPA Sec.171		$5	$5	$5	$5	$5	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$155
Total	$10	$9	$11	$13	$15	$101	$123	$64	$77	$52	$20	$20	$20	$20	$20	$20	$49	$49	$49	$743

NOTE: The waste acceptance schedule does not consider technical attributes, such as the condition of the commercial SNF, that could affect the order and timing in which the Department could accept it for disposal. This estimate also assumes enactment of all necessary legislation, optimal project funding, the issuance of all necessary authorizations and permits, and the absence of litigation-related delays.

EIS = environmental impact statement; LA = license application; NWPA = Nuclear Waste Policy Act of 1982, as amended; SNF = spent nuclear fuel.

5.5.2 Legislative Funding Reform

In the absence of statutory language that authorizes the use of the NWF, the Department expects that the use of any funds from the NWF for a limited demonstration program would be subject to challenge. Thus, any legislation should make clear that construction and operation of the interim storage facility is an authorized use of the NWF.

In addition, in order to provide for the timely and efficient construction and operation of both the interim storage facility and the Yucca Mountain repository, any legislation should include funding reform that ensures that the Department has prompt access to annual fees and interest deposited in the NWF. In the absence of funding reform, interim storage costs would be part of the Department's budget allocation, which would exacerbate the existing problem of competing for limited resources within the Department's budget allocation. Without funding reform, Congressional appropriators and the administration would need to prioritize each year between other Department activities, Yucca Mountain repository efforts, and the development of an interim storage facility for the acceptance of SNF from the nine decommissioned reactor sites.

Legislation providing direction for interim storage without funding reform would further jeopardize the Yucca Mountain project and increase taxpayer liability. Regardless of whether direction is given to begin accepting SNF from decommissioned reactors, the liability costs incurred by the Department's delay under the Standard Contract will increase for every year that the repository is delayed.

5.5.3 Impact on the Adequacy of the Fee

The inclusion of the development and operations of an interim storage facility for the SNF from decommissioned reactors would increase the total system life cycle costs of the repository program under the NWPA. A new fee adequacy assessment would need to be conducted to assess whether the additional near-term costs of an estimated $743 million would have an impact on the nuclear waste disposal fee. The program would be required to construct both an interim storage facility and a repository simultaneously, resulting in significantly higher near-term expenditures.

The adequacy of the fee is based on sufficient investment accumulation for the repository out-year needs after fee revenue is no longer provided to the government. Near-term increases in funding requirements could result in a negative impact on the adequacy of the 1 mill per kilowatt hour fee currently paid by utilities.

6. CONCLUSION

The Department has reviewed its authority to accept SNF from decommissioned nuclear power reactor sites for interim storage and has concluded that it has no such currently exercisable authority. Legislation is required that would eliminate the limitations in the NWPA on taking commercial SNF for interim storage prior to the opening of the Yucca Mountain repository. In addition, in order to undertake interim storage in a timely and efficient manner, legislation would be needed (1) to direct the Department to take SNF from decommissioned nuclear power reactors as soon as possible; (2) to establish an expedited siting process; and (3) to authorize the Department to construct and operate the facility under its regulatory authority, or, if the facility

were to be constructed and operated under an NRC license, to provide for an expedited siting and licensing process. Furthermore, legislation should also provide for funding reform to ensure the Department access each year to the additions to the NWF from fees and interest. Reliable and sufficient funding is necessary for the simultaneous development of the Yucca Mountain repository and an interim storage facility.

While moving the SNF from the nine decommissioned commercial nuclear power reactor sites would demonstrate that the Department can move forward prior to the opening of the repository, any reduction in the Department's liability for failing to begin accepting commercial SNF in 1998 would be minimal. The ongoing liability associated with the Department's delay in waste acceptance (currently $11 billion, assuming that operation of the Yucca Mountain repository begins in 2020) would not be reduced in any significant way and could be increased if providing priority acceptance of the SNF from the nine decommissioned commercial nuclear power reactor sites resulted in additional litigation from contract holders with operating reactors, as well as in demands for acceptance of their SNF at the interim storage facility.

If Congress authorizes the Department to initiate interim storage for the consolidation of the spent nuclear fuel from decommissioned commercial nuclear power reactors and amends the interim storage siting provisions provided in the Nuclear Waste Policy Act of 1982, as amended, the Department would consider either an existing federal site, one or more existing operating commercial nuclear power reactors, or a competitively selected interim storage site, engaging the sites that have volunteered to host Global Nuclear Energy Partnership facilities as part of the competitive process.

Authorization and funding by Congress to perform interim storage would provide the Department an option in addition to Yucca Mountain to allow the Department to begin to meet its contractual obligations with the owners of commercial spent nuclear fuel. This option could prove beneficial should Yucca Mountain experience delays due to licensing, litigation, lack of funding or other causes, but only if the enabling legislation adequately addresses the issues discussed in this report.

7. REFERENCES

10 CFR (Code of Federal Regulations) Part 71. Energy: Packaging and Transportation of Radioactive Material.

10 CFR Part 72. Energy: Licensing Requirements for the Independent Storage of Spent Nuclear Fuel, High-Level Radioactive Waste, and Reactor-Related Greater than Class C Waste.

10 CFR Part 961. Energy: Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste.

59 FR 27007. Notice of Inquiry on Waste Acceptance Issues.

60 FR 21793. Office of Civilian Radioactive Waste Management; Nuclear Waste Acceptance Issues.

Atomic Energy Act of 1954. 42 U.S.C. 2011 et seq.

Atomic Energy Act of 1954, as amended. 42 U.S.C. 2075 et seq.

Consolidated Appropriations Act, 2008. Public Law No. 110-161. 121 Stat. 1844.

Construction Authorization. 42 U.S.C. 10168 et seq.

Domestic Distribution. 42 U.S.C. 2111 et seq.

Energy Reorganization Act of 1972.

Findings and Purposes. 42 U.S.C. 10131 et seq.

Foreign Distribution of Byproduct Material. 42 U.S.C. 2112 et seq.

Interim Storage Fund. 42 U.S.C. 10156 et seq.

National Environmental Policy Act of 1969. 42 U.S.C. 4321 et seq.

Nuclear Waste Fund. 42 U.S.C. 10222 et seq.

Nuclear Waste Policy Act of 1982. 42 U.S.C. 10101 et seq.

Policies Contained in International Arrangements. 42 U.S.C. 2152 et seq.

Purpose of Chapter. 42 U.S.C. 2013 et seq.

Research and Development Assistance. 42 U.S.C. 2051 et seq.

Site Selection. 42 U.S.C. 10165 et seq.

Storage of Spent Nuclear Fuel. 42 U.S.C. 10155 et seq.

Transportation. 42 U.S.C. 10157 et seq.

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Comments of the Institute for Energy and Environmental Research on the U.S. Nuclear Regulatory Commission's Proposed Waste Confidence Rule Update and Proposed Rule Regarding Environmental Impacts of Temporary Spent Fuel Storage[1]

Arjun Makhijani, Ph.D.
President, Institute for Energy and Environmental Research
6 February 2009

The following are the comments of the Institute for Energy and Environmental Research (IEER) on the Nuclear Regulatory Commission's (NRC's) proposed Waste Confidence Decision Update[2] and the associated Consideration of Environmental Impacts of Temporary Storage of Spent Fuel after Cessation of Reactor Operation.[3]

The proposed Waste Confidence Decision warrants careful examination, because it serves as the underpinning to several key safety and environmental findings regarding the operation of nuclear power plants and the disposal of the wastes that they generate.

- First, the Waste Confidence Decision presents a safety finding, under the Atomic Energy Act, that the NRC has reasonable assurance that disposal of spent fuel will not pose an undue risk to public health and safety. It does so via the finding that disposal is technically feasible and can be done in conformity with the assumption of zero releases in Table S-3 at 10 CFR 51.51, which specifies the environmental impacts associated with nuclear reactor operation, including those associated with nuclear wastes and emissions.
- Second, the Waste Confidence Decision provides the basis for a key assumption in the uranium fuel cycle rule that spent fuel can be isolated in a repository, with no radioactive releases. That finding, in turn, is key to the NRC's conclusion that the environmental impacts of the entire uranium fuel cycle are insignificant.[4]

[1] These comments were prepared at the request of Texans for a Sound Energy Policy. Some typos were corrected on October 24, 2013.
[2] NRC 2008
[3] NRC 2008b
[4] 10 CFR 51.51 2008 and its Table S-3 2008

- Finally, the Waste Confidence Decision provides the basis for the NRC's Finding of No Significant Impact (FONSI) regarding the environmental impacts of temporary spent fuel storage pending its disposal in a repository.

As discussed below, IEER believes that the NRC lacks adequate support for the Waste Confidence Decision's first and second proposed findings. The NRC has simply failed to address currently available information which shows that the NRC currently does not have an adequate technical basis for a reasonable level of confidence that spent fuel can and will be isolated in a geological repository.

The NRC's lack of support for Findings 1 and 2 of the Waste Confidence Decision also fatally undermines the viability of the uranium fuel cycle rule promulgated in 1979.[5] In that rule, the NRC declared that the environmental impacts of the entire uranium fuel cycle would be negligible. The finding was based in part on the assumption that spent fuel would have no radioactive releases after it was placed in a repository. That assumption was based in turn on two other assumptions: (i) that disposal of spent fuel or reprocessing high-level waste would be in a salt repository, and (ii) that releases of radioactivity from that repository would be zero. In its draft Waste Confidence Decision, the NRC has acknowledged that salt is not a suitable medium for spent fuel disposal. Investigations of Yucca Mountain and other non-salt repositories have concluded that there are likely to be some releases of radioactivity due to spent fuel disposal. This invalidates the basis of the uranium fuel cycle rule and the Waste Confidence Decision that is associated with it. Other assumptions and findings contained in the 30-year-old uranium fuel cycle rule are also demonstrably invalid today, such as the assumption that greater than class C (GTCC) waste and depleted uranium (DU) tails can be disposed of in a shallow land burial as low-level radioactive waste (LLRW) under present rules. On the contrary, special permitting processes, including environmental impact evaluations will be necessary to dispose of these wastes. The NRC must re-evaluate all of these assumptions and findings in light of new information which shows that they are incorrect. And the NRC must re-evaluate its overall conclusion that the health impacts of the uranium fuel cycle are negligible.

In addition, the NRC's lack of an adequate basis for Findings 1 and 2 undermines the NRC's basis for a finding that spent fuel can be safely stored on reactor sites pending the opening of a repository. The NRC must conduct a new environmental analysis that examines the impacts of onsite spent fuel storage for a much longer period than 50 to 60 years after the cessation of reactor operations. This must include considerations relating to the potential deterioration of onsite storage canisters and the potential for transfers to new onsite storage canisters.

Finally, taken together, the Waste Confidence Decision, the uranium fuel cycle rule, and the NRC's environmental analysis of the impacts of temporary fuel storage completely fail to address one of the key environmental questions raised by the proposed licensing and re-licensing of nuclear plants: what does it cost to manage and dispose of the radioactive waste generated in the process of operating nuclear plants, and is the cost

[5] NRC 1979

justifiable in comparison to renewable energy alternatives such as wind and solar power? The lack of a credible cost analysis for waste means that alternatives to nuclear power cannot be fairly evaluated as required by NEPA.

A. Comments on Finding 1

The NRC proposes to reaffirm Finding 1 unchanged from 1990. Finding 1 reads as follows:

> Finding 1: The Commission Finds Reasonable Assurance That Safe Disposal of High-Level Radioactive Waste and Spent Fuel in a Mined Geologic Repository Is Technically Feasible.[6]

Three terms in Finding 1 are critical:

- "reasonable assurance"
- "safe disposal", and
- "technically feasible"

The term "safe disposal" involves (i) the safety of building the repository, putting the waste in it, and backfilling and sealing it, and (ii) the performance relative to health and environmental protection standards for a long period after the repository is sealed. It should be noted that the requirements of showing that there is "reasonable assurance" that "safe disposal" of "high-level waste and spent fuel" is "technically feasible" are much greater than would be the case if the problem were simply to show that it is possible to dig a deep mine, put spent fuel in it, and backfill it. That would be nothing more than dumping. In the case of a geologic repository system, it is essential to show a reasonable basis for confidence that the public and the environment far into the future will be adequately protected from the effects of disposal at a specific site and a specific engineered system built there.

A scientific explanation of the term "reasonable assurance" requires either physical proof that such a facility exists and has operated within expected performance rules or a statistically valid argument based on real-world data that would show (i) that all the elements for a repository system exist and (ii) that they would work together as designed, as estimated by validated models. The evidence must be sufficient to provide a reasonable basis to conclude that the durability of the isolation arrangements would be sufficient to meet health and environmental standards for long periods of time – hundreds of thousands of years with a high degree of assurance, or in other words, with a high probability. In statistical terms, this means that the upper bound estimate of health and environmental damage should be below the maximum allowable limit with a high level of confidence. At present these uncertainties are very large, which means that it is reasonable to conclude that under some circumstances the damage could be higher than the norms of radiation protection. See below for examples.

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[6] NRC 2008, p. 59553.

The task of determining whether there is an adequate basis for a reasonable assurance of technical feasibility is very difficult. A large part of the difficulty so far as assessing long-term integrity and performance arises from the fact that three elements of a mined system that is highly perturbed thermally, chemically, and mechanically from its original geologic state must be shown to work together to provide "safe disposal" – that is to provide disposal that will conform to an agreed and settled radiation protection standard for the public and that will also protect workers during the construction period of the repository according to prevailing norms for worker protection. The three elements are:

- The waste and the waste encapsulation system.
- The backfill and sealant system.
- The near- and far-field perturbed geologic environment.

We will show that it is a very difficult and complex task to assess the performance of each of these elements under the conditions of spent fuel disposal in a repository and that a wide range of radiation doses can be estimated from the same general repository type and location, including doses that are above regulatory limits.

1. Lack of realistic demonstration of the technical feasibility of a thermally perturbed, sealed repository system

To date, no large-scale demonstration of a system that has been thermally perturbed by spent fuel and then back-filled and sealed has been carried out even for a limited period of time. Much less has there been a demonstration over a few decades that a highly thermally perturbed and sealed system with large amounts of spent fuel would function in the long-term as estimated on paper or via the results of limited experiments. Moreover, many of the experiments that have been proposed, even in highly regarded repository programs, are simply inadequate or inappropriate for estimating performance. For instance, an expert team of geologists put together by IEER[7] concluded that both the thermal and mechanical aspects of the research designed to study the suitability of the French repository location were deficient in essential respects, despite the fact that the program had many strong points:

> A crucial problem for research is that the model must estimate performance not of the natural setting but of a geologic system that has been considerably disturbed by a large excavation, which may induce fractures not originally present, by the introduction of (thermally) hot wastes, and by the addition of various backfill materials and seals. *Hence, the system being modeled is no longer the original geologic system, but a profoundly perturbed system.* …. Estimation of performance of a system under these conditions with some confidence poses challenges that are, in many ways, unparalleled in scientific research.
>
> In the specific case of the Bure site, the host rock is argillite, a hard rock consisting of clayey minerals, carbonates (mainly calcites), and quartz. The in-tact rock is not very porous, leading to expectation of diffusive flow in the

[7] See Attachment B for the Curriculum Vitae of the team members.

absence of fractures and in the absence of disturbance by mining. Such flow would be very slow and the expected travel time of radionuclides released from waste packages could be very long.

> However, the IEER team's evaluation of (i) the documents, (ii) argillite rock properties under conditions of heat and humidity, and (iii) the research done to model the site performance indicated that the actual conditions prevailing in an actual repository could be very different from diffusive flow. Failure of certain components, notably repository seals, could result in rapid (in geological terms) transport of radionuclides to the human environment.
>
> ANDRA's own estimate of dose under conditions of seal failure was higher than the allowable limit of 0.25 millisieverts (25 millirem) per year. In this context, IEER concluded that ANDRA's scenario for human exposure was not necessarily conservative, in that doses to an autarchic farmer family (also called "subsistence farmer family") using groundwater in certain locations could be even higher than the dose at the surface water outcrop estimated by ANDRA.[8]

Note that as of the date of the IEER report on the Bure site in France, ANDRA's own estimate of dose exceeded its regulations in the event of seal failure. In this context, research on characterizing the long-term integrity of seals becomes critically important. And IEER found ANDRA's research program in this very area to be deficient. One of its principal conclusions about the research on seals was that it seemed to of "marginal value" and was far from adequate to enable a sound determination of repository performance:

> One crucial problem is that the simulated slot sealing test in the underground laboratory may be of marginal value and utility. The test is planned to be done very early on after excavation and only over a very short period of time relative to the duration of performance requirements and even relative to the time lapse over which the actual EDZ [Excavated Damaged Zone] will develop, prior to seal installation. This is neither convincing nor satisfactory. It is difficult to see how and why increasing the stress component parallel to the gallery walls will reduce the permeability in that direction or how a flatjack can simulate a bentonite seal, except in the most crude of approaches.[9]

Similarly, there has been considerable skepticism about the DOE's proposed disposal configuration for Yucca Mountain. DOE proposes disposal in the unsaturated zone in a configuration in which boiling of water is expected for "the first few hundred years after closure…in the drift vicinity."[10] The DOE expects the effects to be as follows:

[8] Makhijani and Makhijani 2006. Italics in the original. This article is based on the full report, which is in French: *Examen critique du programme de recherche de l'ANDRA pour déterminer l'aptitude du site de Bure au confinement géologique des déchets à haute activité et à vie longue : Rapport Final*. Hereafter cited as IEER 2005. The qualifications of the team members are found in Attachment C.
[9] IEER 2005, p. 59, in Chapter 2. Retranslated from the final French report by Annie Makhijani.
[10] DOE 2008 p. 2.3.3-58 in Chapter 2

> Thermal expansion of the rock matrix induces thermal stresses and associated changes in flow properties near emplacement drifts…. Thermally-driven effects also cause dissolution and precipitation of minerals, which may affect flow properties (thermal-hydrologic-chemical effects). [11]

While the DOE believes that these processes will not prevent satisfactory repository performance, Dr. Don Shettel, an expert geochemist and consultant for the State of Nevada, has concluded that a hot temperature design is "fatally flawed."[12] This was extensively discussed at the May 18, 2004, meeting of the U.S. Nuclear Waste Technical Review Board (NWTRB):

> We've talked about thermal concentration of brines and boiling point elevation. We can get fingering of concentrated solutions in fractures, thereby increasing the probability and percentage of thermal seepage waters that might reach the drift on the EBS [Engineered Barrier System]. We have mixed salt deliquescence [absorption of water vapor by solid salts so as to dissolve them], not so much from the dust that's on the canisters, but from the increased amount of thermal seepage water that we believe can reach the EBS. And, if these evaporated or concentrated solutions can reach the EBS before the thermal peak, then they can become, even after the thermal peak, get hydrated salts with thermal decomposition, with the evolution of acidic solutions and vapors. And, **one of the most important aspects of this model is the wet-dry cycling or intermittent seepage**. If you get some seepage on the canisters, and it evaporates to some extent, dries out, the addition of water to that can generate acid.
>
> ….We believe that the **high temperature design for the repository is fatally flawed** for the number of reasons that I've discussed, and that **emplacement in the saturated zone would be much better, because that's essentially where DOE has tested their metals at.** And, the saturated zone is also the much less complicated in terms of processes and modeling.[13]

It is clear from the above, that there are scientists who have carefully studied the problem who believe that DOE has tested the metals mainly in an environment [saturated] that is fundamentally different than the proposed disposal environment [unsaturated]. According to them the proposed DOE design is "fatally flawed" and the Yucca Mountain repository site is "not adequate." Dr. Shettel also stated that an entirely different disposal concept in the saturated zone would be "much better."[14]

Testing, experiments, and models that seem to bypass essential questions were a problem that the IEER team discovered in relation to sealants, as quoted above (proposed tests were "neither convincing nor satisfactory"). Moreover, the problem of wet-dry cycling and inadequate modeling was also cited by the IEER team as a significant problem in the French repository research program:

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[11] DOE 2008 p. 2.3.3-58 in Chapter 2

[12] Don Shettel is Chairman and Geochemist, Geoscience Management Institute, Inc.

[13] Shettel 2004. Emphasis added.

[14] Also see below for further discussion of the corrosion problem.

> No evidence is found for any model evolution from simple, scoping, or conceptual models into design base models that result in conceptual design and site evaluation. Model evaluation potentials against direct, experimental results have been omitted. The simple models described in the documents do not seem to be adequate for the evaluation/verification of thermophysical site properties.
>
> It is not clear why one-dimension model results are included in the inverse modeling of in situ experiments; the heat flow is not remotely a linear, one-dimensional problem. Even the two-dimensional, analytical model result for an infinite heater length is a very poor model for the arrangement involving a 2 m-long heater only. The large difference between the two-dimensional, analytical, and three-dimensional, numerical models disqualifies the other models. It is even questionable whether the model condition of a three-dimensional domain assuming homogeneous and isotropic material/physical properties is adequate, since the stratigraphy of the Bure site is layered with different properties in different directions.
>
> The thermal conductivity, one of the most important thermophysical site characteristic, has not been adequately established. The standard deviation of this parameter is unusually high, leaving a large margin of uncertainty in the heat-rejecting capacity of the site. The number of samples used for establishing thermophysical site properties based on laboratory samples appears to be low, especially considering the potential spatial variation of these properties over the proposed storage area.
>
> Although the temperature regime according to the baseline design is below-boiling, above-boiling operation is not impossible. A bi-stable system, involving either below boiling or above boiling conditions in the emplacement area, is quite possible under some circumstances. A steam cycle therefore is possible under certain heat load conditions, namely, if the backfill buffer material cannot saturate and the damaged zone cannot re-saturate due to vapor-phase water loss caused by the condensing zones of the emplacement area.
>
> Since above-boiling point temperatures are expected in the Type C and spent fuel modules for long periods of time in the preferred design selection, these modules may develop continuous steam cycles within the emplacement area for centuries.[15]

There is experimental evidence that result of wet-dry cycling at Yucca Mountain could result in very rapid corrosion of the C-22 alloy containers. While the DOE believes the contrary, Dr. Roger Staehle, who worked as a consultant for the State of Nevada with a research team including other experts and Catholic University of America faculty, made a presentation to the NWTRB during which he went through the team's experimental findings for the NWTRB; he concluded with a set of stark "warnings":

[15] IEER 2005, pp. 101-102, Chapter 3. Retranslated from the final French report by Annie Makhijani.

Warnings

1. There is an abundance of warnings as well as solid quantitative data that demonstrate that corrosion of the C-22 alloy is *inevitable and rapid.*

2. A good paradigm for the warnings about C-22 can be found with Alloy 600 that was widely used in the nuclear industry as tubing in steam generators and as structural components. Alloy 600 has broadly failed in these applications, and present failures could easily have been predicted from past occurrences.

3. There are now *abundant warnings that that C-22 alloy is not adequate nor is the present design of the repository adequate*. Such warnings are founded on warnings, some of which are 15 years old.

4. Further, there is abundant evidence that the YM site itself is not adequate.

5. The analogies of warnings from the present nuclear industry are abundant and apply directly to whether the present design at YM is adequate. *The answer is that it is not.*

6. Some of the warnings from experience of the water cooled nuclear reactor industry apply directly to the design and development of the Yucca Mountain facility. These should be carefully assessed, e.g. as they apply to heated surfaces.

7. Finally, the incapacity to inspect the YM containers requires assurances of reliable performance that are higher than those of normal industrial expectations.[16]

The problem of adequacy of the research program or lack thereof points up the critical need to have confidence in each of the three elements of geologic disposal. In the above examples, we have shown that in the case of Yucca Mountain the behavior of the containers as well as the rest of the Engineered Barrier System has not been characterized to the point that independent scientists could agree that Yucca Mountain is a suitable disposal site, even though the DOE believes it is. On the contrary, there is quite a bit of evidence that Yucca Mountain is not a suitable site, and may even be "fatally flawed," since the containers are essentially the only effective barrier preventing radionuclide releases to the environment.

The Nuclear Waste Technical Review Board considered the question of the potential for severe corrosion due to deliquescence at length following the May 2004 meeting from which the above presentation is drawn. While the twists and turns that the issue took are technically interesting and illustrate the uncertainties, the most important point to note here is that, in the end, the DOE decided to entirely ignore the issue because it believes it to be "insignificant":

> Although deliquescence of salts on the waste package surface is expected to occur, this process has been excluded from TSPA [Total System Performance Assessment] because the effects of such deliquescence have been determined to be insignificant to performance (Table 2.2-5, FEP 2.1.09.28.0A, Localized corrosion on waste package outer surface due to deliquescence). The physiochemical characteristics of brines produced through deliquescence of minerals in deposited dusts are not expected to generate an environment favorable for the initiation of localized corrosion and

[16] Staehle 2004. Italics added.

> propagation for Alloy 22 (UNS N06022) waste packages. In addition, at elevated temperatures (greater than 120°C), only small quantities of brine will form from the available dust, and brine volume will limit the extent of localized corrosion damage should it initiate.[17]

And again:

> Modeling of evaporative evolution of potential seepage waters shows that corrosive calcium and magnesium-chloride brines are not expected to form. As noted above, although deliquescence-induced brine formation is expected to occur, this process has been excluded from TSPA because the effects of such deliquescence have been determined to be insignificant to performance.[18]

The Nuclear Waste Technical Review Board, the expert oversight body appointed by Congress to oversee the Yucca Mountain program, came to a somewhat different conclusion regarding whether deliquescence-induced corrosion should be excluded from DOE's license application:

The NWTRB's report was sent to Congress with a letter dated August 2008, two months after the DOE had submitted its license application concluding that deliquescence-induced corrosion could be ignored in performance assessment because it was judged to be insignificant. For this very reason, the report is worth quoting at length:

> The Board's January 12, 2007, letter [to the DOE Office of Civilian Radioactive Waste Management] and its attached report contained the following additional findings:
>
> - *Cumulative damage due to the combined effects of deliquescence-induced localized corrosion and seepage-based localized corrosion merits some analysis.*
> - *Including seepage-based localized corrosion in TSPA-LA while excluding deliquescence-induced localized corrosion is incongruous because the process (localized corrosion) is the same in both cases.*
> - *Deliquescence-induced general corrosion of Alloy 22 should be included in TSPA-LA.*
> - Anomalies among recent experiments at high temperatures, such as unexpectedly high general corrosion rates and a maximum of general corrosion rate with respect to temperature, require explanation.
> - Effects of waste package surface condition on the corrosion of the waste package surface may need more investigation.
> - *Including deliquescence-induced localized corrosion in TSPA-LA would add to its completeness, robustness, and credibility.*
>
> In a follow-up letter to OCRWM dated July 10, 2007 (Garrick 2007c), the Board pointed out that the dust settling on waste package surfaces during ventilation would contain significant amounts of organic materials and that reactions between these materials and nitrate in the dust could affect the amount of nitrate, which inhibits

[17] DOE 2008, p. 2.3.5-10
[18] DOE 2008, p. 2.3.5-12

> localized corrosion if present in large enough quantities relative to chloride. The Board stated that the Project should analyze the effects of the full range of factors (e.g., organics in dust, acid-gas devolatilization, and radiolysis) that could influence whether inhibitive nitrate-to-chloride ratios persist under repository conditions.
>
> OCRWM responded to the Board's January 12, 2007, and July 10, 2007, letters in a November 20, 2007, letter (Sproat 2007c). Although the Board agrees with some of the points mentioned in the letter, **in several instances OCRWM did not address points brought up by the Board. For example, in its January 12 letter, the Board addressed the apparent incongruity of excluding deliquescence-induced localized corrosion while including seepage-based localized corrosion despite the fact that both are the same process, i.e., localized corrosion**. In its November 20, 2007, letter, the Project reiterated the differences in the environments between deliquescence-induced and seepage based localized corrosion. The Board concurs that the environments are quite different, but the processes are not. **Regardless of whether NRC regulations allow a process to be split in two and one part to be discarded, doing so still remains incongruous.**
>
> In addition, the Project refers to components of the dust deposited on waste package surfaces as "reactants" or "limited reactants" in several places in its November 20 letter. Although the Board agrees that many components in the dust could be reactants, it seems that the principal reactants in general or localized corrosion would be either the water component of deliquescent brines or oxygen dissolved in the brines. Both water and oxygen are essentially limitless in supply. If they are consumed by the brine in corrosion reactions, they simply will be replenished rapidly by dissolution or deliquescence. The Board would welcome additional information from the Project about what other components of the dust undergo reactions. **Finally, although OCRWM claimed that it had addressed Board concerns about the effects of organic materials on the nitrate-to-chloride ratio in the November 20 letter, the basis for this claim is unclear.**
>
> **In sum, despite the workshop in September 2006 and the exchange of letters in 2007, the issue of deliquescence-induced localized corrosion, although apparently tractable, remains open.**[19]

In other words, on perhaps the most critical scientific uncertainty for the entire Yucca Mountain program, the DOE has

- failed to follow the advice of the Congressionally mandated Technical Review Board
- submitted a license application that dismisses as "insignificant" the very process that the NWRTB asked it to include and address further and that has led some scientists with considerable expertise to conclude that Yucca Mountain is not an adequate site or that the design is "fatally flawed."

There is no evidence in the draft Waste Confidence Decision that the NRC has taken any of this information and analysis into account in reiterating Finding 1 that there is "Reasonable Assurance That Safe Disposal of High-Level Radioactive Waste and Spent Fuel in a Mined Geologic Repository Is Technically Feasible." Further, the NRC draft

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[19] NWTRB 2008, pp. 27-28, italics and bold emphasis added.

Decision also notes that salt repositories are unsuitable for disposal of spent fuel (see below).

2. Uncertainty in performance results and the question of technical feasibility

The technical feasibility of "safe disposal" of waste in a geologic disposal system with "reasonable assurance" must be judged according to technically sound and legally valid performance criteria. There are two issues that relate to "technical feasibility" in this context

a. What is the nature of the performance standards that must be met? This relates to the radiation protection standard set to protect the health and environment of future generations from the effects of waste disposal.
b. Is there reasonable assurance that the performance standard can be met and that other safety goals, such as worker safety during constructing, waste emplacement, and sealing, can also be met? This relates to a reasonable level of scientific and statistical confidence that the performance standard in terms of health and environmental protection will be met in practice.

a. Nature of the Performance Standard

The history of the process of specifying the standards of performance, such as maximum allowable dose, the pathways via which that dose must be assessed, and the period over which performance must be evaluated, in the United States undermines the NRC's claim of technical feasibility. The claim is also undermined by estimates of performance that cover a wide range and include at the upper limit large exceedance of the current EPA radiation dose requirement.

EPA standards for disposal of spent fuel, high-level waste, and transuranic waste were first promulgated in 1985 and amended later on to include drinking water protection.[20] The rule specified a period of protection of 10,000 years. Yet the National Research Council study done for the DOE in 1983[21] had already criticized the EPA proposal before its finalization and advocated extending the period of performance for all time, judging compliance for the proposed period of 10,000 years to be "rather easy."[22] The National Research Council also advocated a maximum individual dose approach rather than a population dose approach.

The EPA essentially ignored the National Research Council's advice and adopted the 10,000 year limit and limits on total releases of certain radionuclides including carbon-14. The EPA standard was to be the fundamental performance criterion for public health and environmental protection for spent fuel, high-level waste, and transuranic waste disposal.

[20] The regulation is 40 CFR 191, and can be found on the Web at http://www.access.gpo.gov/nara/cfr/waisidx_08/40cfr191_08.html.
[21] NAS-NRC 1983 Chapter 8.
[22] NAS-NRC 1983 p. 236.

Further study showed that the National Research Council's conclusion that a 10,000 year limit would make compliance "rather easy" to be incorrect with respect to unsaturated repositories like Yucca Mountain with respect to the specific standard adopted by the EPA. Specifically, the EPA set a limit of carbon-14 emissions of 100 curies per 1,000 metric tons of heavy metal in spent fuel or equivalent high-level waste.

An EPA panel was convened to examine the question of carbon-14 releases from unsaturated repositories like Yucca Mountain. In 1993, the Science Advisory Board of the EPA cast considerable doubt on whether Yucca Mountain, a proposed unsaturated repository, could meet the carbon-14 emission limit in the EPA standard:

> …[I]t is not possible on the basis of presently available information to predict with reasonable confidence whether releases from an unsaturated repository would be less than or greater than the Table 1 (40 CFR 191) release limits. (The Table 1 release limit is one-tenth of the inventory.)[23]

Instead of looking for a new repository that might meet the standard, Congress mandated special standards for Yucca Mountain, which may, in light of the process, be fairly called a double-standard-standard. The scientific basis of these standards was to be provided by the National Academy of Sciences.

The National Research Council of the National Academies issued a report in 1995 advocating a period of performance extending to the peak dose and a rather complex method of estimating the peak dose.[24] The latter itself generated sufficient controversy that one of the panel members, Professor Thomas Pigford, one of the most prominent nuclear engineers in the United States (and one of the authors of the 1983 National Research Council report), wrote a dissent. He concluded that the methods of dose calculation "in Appendix C are not mathematically valid."[25] He concluded that the method adopted

> would introduce unjustified and unprecedented leniency in public health protection from radioactive waste.

and that

> probabilistic exposure scenario [in Appendix C of the National Research Council's 1995 report] will be perceived by many as a disguised means of reducing the calculated individual doses below the high values (ca. 10 rem per year) that were presented to the committee. **Better repository design is the proper means of obtaining low doses, not by nonscientific policy fixes**. **Policy makers must reject pressures for short-term expediency and economy, lest, by enacting policy that compromises scientific**

[23] Loehr, Nygaard, and Watson 1993
[24] NAS-NRC 1995, Appendix C.
[25] NAS-NRC 1995, Appendix E, p. 177.

> **validity and credibility, it undermines public confidence** and puts and end to all further nuclear development and research.[26]

In 2001, the EPA proposed a new standard that applied only to Yucca Mountain. Contrary to the advice of the National Research Council report of 1995, it limited the period of performance to 10,000 years.[27] This was invalidated in court and then the EPA proposed a revised draft standard in 2005.[28] That proposed standard was far more lax for the period from 10,000 to 1 million years than any radiation protection standard protecting today's population. At 350 millirem per year, the lifetime risk of fatal cancer to women would be as high as 1 in 62. Higher doses to some people were permitted. For a small minority, doses as high as 2 rem would be permitted leading to a lifetime fatal cancer risk of 1 in 10.[29]

The EPA published its final rule in 2008. It limits doses in the first 10,000 years to 15 millirem per year committed effective dose equivalent, and to 100 millirem per year in the 10,000 to 1 million year period.[30]

The State of Nevada has sued the EPA over these final standards.[31] It should be noted in this context that the courts have twice before invalidated EPA "final" rules in regard to deep geologic repositories. Further the NRC has also changed its rules. In the early stages, following the 1980 DOE EIS on geologic disposal it was assumed that the containers would be the main barrier for an initial period, such as 1,000 years, but that the geologic setting would perform the main job of preventing long-lived radionuclides from reaching the human environment.

In sum, after more than a quarter of a century of trying to come up with a standard that would apply to spent fuel disposal at a proposed repository (40 CFR 191 applies to spent fuel disposal but no repository is proposed to which it might apply and it does not apply to the only one that is proposed), the matter of a final standard is still unsettled in that it is under litigation. Without a final standard that is clear of court challenges, performance assessment must necessarily rest on guesses about what it might be; this is not a basis on which "reasonable assurance" of the technical feasibility of "safe disposal" can be given, for the simple reason that there is no accepted definition of safe in relation to Yucca Mountain as yet. This is the current situation even if it could be shown that Yucca Mountain could conform to postulated rather than actual settled dose limits.

And, as it happens, there is no reasonable assurance as yet that Yucca Mountain can meet the final standard that the EPA has now in place at 40 CFR 197.

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[26] Pigford 1995, emphasis added.
[27] EPA 2001.
[28] EPA 2005
[29] Makhijani and Smith 2005. The original standard 40 CFR 191 has no specified public health protection beyond 10,000 years.
[30] EPA 2008
[31] Nevada v. EPA 2008 (State of Nevada v. Environmental Protection Agency (D.C. Cir., No. 08-1327, consolidated with No. 08-1345))

b. Evaluating performance

We will assume for the purpose of this section that the EPA standard for Yucca Mountain at 40 CFR 197 is the one against which “safe disposal” is to be judged as it concerns protection of future generations. In this limited context, a reasonable assurance of the technical feasibility of safe disposal at Yucca Mountain must show that there is a high probability that the standard will be met. This requires that the performance assessment that estimates the dose be generally accepted in the scientific community and that reasonable technical questions raised by experts on critical issues have been resolved. This is not the case with Yucca Mountain.

Analysis provided to the Nuclear Waste Technical Review Board indicates that the geologic setting of Yucca Mountain contributes essentially nothing to the performance of the site. This can be seen from the set of DOE graphs in Attachment A, which is a part of these comments. Specifically, Graph A, the first one in Attachment A, shows that in the absence of the container, a dose limit of 15 millirem would be greatly exceeded in much less than 10,000 years. Graph A shows that a 25 millirem per year dose limit, which was the norm against which the DOE was assessing compliance at the time, would be exceeded as soon as 2,000 years after closure and the peak dose would be on the order of 1,000 millirem well before 10,000 years. This is more than 60 times the EPA dose limit for the period less than 10,000 years. All of the other graphs show that if the container stays intact, the failure of another part of the overall system would not affect doses much in the first 10,000 years. (The peak dose beyond 10,000 years exceeds the limit in 40 CFR 197 in all cases in this set of DOE graphs – see below).

This puts a premium on the integrity of the container because it is the one element that would ensure compliance (according to the DOE model) in the period less than 10,000 years. This DOE conclusion that the container is practically the only barrier to the release of radioactivity has also been expressed before the Nuclear Waste Technical Review Board by an independent expert, Roger Staehle (also quoted above):

> The central question that we're all considering here is really the integrity of the container. So, whatever we're thinking about has to be directed toward the integrity of the container, because that's **the primary or virtually the only barrier to release of radioactivity**. [32]

As we have noted above, the question of whether the containers will endure for very long is, at best, an open one. There is clear evidence that they may corrode quickly relative to time scales required for assessing performance.

If they do corrode quickly, then the situation described in Graph A of Attachment A, that is, doses tens of times greater than the present final EPA standard prior to 10,000 years will prevail. The DOE itself has calculated doses for the repository that vary widely, indeed, wildly. For instance, the most recent estimate, in DOE’s license application for the Yucca Mountain repository shows peak doses that would be more than 100 times

[32] Staehle 2004 p. 241.

lower than the final EPA standard of 100 millirem per year (beyond 10,000 years) discussed above.[33] But the peak doses shown in Attachment A (base case), prepared by the DOE for the NWTRB, are about an order of magnitude higher than the 100 millirem standard – that is, they are a thousand times bigger than the estimate in the DOE license applications. As another example, the DOE had estimated doses as high as 10 rem in a presentation to the National Research Council, or ten thousand times higher than the estimate in the license application (see Dr. Pigford's quote above). Finally, DOE's peak dose estimates in its 2002 Final Environmental Impact Statement for Yucca Mountain are also much higher than the 100 millirem per year dose to the maximally exposed individual. The Table below is reproduced from DOE's Final EIS for Yucca Mountain. Even the mean dose to the "reasonably maximally exposed person (RMEI)" is greater than 100 millirem. The 95 percentile dose for the "reasonably maximally exposed person" is far higher – 510 millirem. Should the population 18 kilometers from Yucca Mountain be in the thousands, many individuals would be expected to have doses considerably in excess of 500 millirem, since this value is a 95th percentile estimate. We note that even 30 kilometers away, where people live today, the 95 percentile peak dose is much greater than 100 millirem per year.

Table 5-12. Impacts for an individual from groundwater releases of radionuclides during 1 million years after repository closure for the lower-temperature repository operating mode.

Individual	Mean		95th-percentile	
	Peak annual individual dose (millirem)	Time of peak (years)	Peak annual individual dose (millirem)	Time of peak (years)
At RMEI location[a]	120[b]	480,000	510[c]	410,000
At 30 kilometers[d]	83[e]	NC[f]	350[e]	NC
At discharge location[g]	48[e]	NC	240[e]	NC

a. The RMEI location is approximately 18 kilometers (11 miles) downgradient from the repository.
b. Based on 300 simulations of total system performance, each using random samples of uncertain parameters.
c. Represents a value for which 285 out of the 300 simulations yielded a smaller value.
d. 30 kilometers = 19 miles.
e. Estimated using scale factors as described in Section 5.4.1.
f. NC = not calculated (peak time would be greater than time given for the RMEI location).
g. 60 kilometers (37 miles) at Franklin Lake Playa.

Source: "Chapter 5: Environmental Consequences of Long-Term Repository Performance," p. 5-29, in Volume I of *Final Environmental Impact Statement for a Geologic Repository for the Disposal of Spent Nuclear Fuel and High-Level Radioactive Waste at Yucca Mountain, Nye County, Nevada,* DOE/EIS-0250 (U.S. Department of Energy, February 2002), on the Web at http://www.ocrwm.doe.gov/documents/feis_a/vol_1/eis05_bm.pdf.

In sum, at the present juncture, it is impossible to say with any reasonable assurance what the radiation doses to the public from a Yucca Mountain repository would be. The DOE itself has in the last few years calculated doses that are different by a factor of 1,000, ranging from compliance to non-compliance. The DOE has dismissed the potential for severe corrosion due to deliquescence as insignificant. But that possibility cannot be ruled out on the basis of present scientific evidence. As discussed above, the DOE chose to disregard the advice of the NWTRB on this matter.

[33] DOE 2008, Table 2.4-2, p. 2.4-357.

This demonstrates that there is not enough scientific basis for "reasonable assurance" that waste can be disposed of at Yucca Mountain safely for the durations envisaged. On the contrary, the uncertainties continue to be high and the possibility that Yucca Mountain could suffer a complete failure (be "fatally flawed") cannot be reasonably excluded. The NRC does not assume that Yucca Mountain will be licensed. But its draft Finding 1 has not taken into account the data and analysis that indicate the potential that it may not meet EPA's standard and therefore cannot be any part of the basis for its Finding.

Another example throws considerable light on the issue. For decades it was assumed that salt was a suitable medium for high-level waste and spent fuel disposal. Salt sites were part of the DOE's first round set under the Nuclear Waste Policy Act (NWPA). Over the decades DOE has investigated several sites in salt formations. One of the top three sites that DOE selected for characterization for spent fuel disposal was a salt site (in Texas); the others were on federally controlled land in Washington State (the basalt site at Hanford) and Nevada (the volcanic tuff site at Yucca Mountain).[34] But now the NRC itself considers salt as unsuitable for spent fuel disposal. According to the draft waste confidence rule:

> Salt formations currently are being considered as hosts only for reprocessed nuclear materials because heat-generating waste, like spent nuclear fuel, exacerbates a process by which salt can rapidly deform. This process could potentially cause problems for keeping drifts stable and open during the operating period of a repository.[35]

The problem of salt being an inappropriate medium for spent fuel disposal is linked to a larger problem of waste confidence as it relates to assessment of the environmental impact from the licensing of reactors. This issue concerns the obsolescence and incorrectness of the governing regulation for reactor licensing, 10 CFR 51, which sets forth "environmental protection regulations applicable to NRC's domestic licensing and related regulatory functions."[36] It is connected to the Waste Confidence Rule and is discussed in Section C below.

The NRC also did not consider the third geologic formation that was in the DOE's top three: the basalt formation at the Hanford Washington site. Many serious defects of the site, including very serious problems in safety, were noted by one of the leading geologist in the United States, Donald E. White, who was a member of the National Research Council panel that wrote a report for the DOE on geologic isolation. In regard to safety Dr. White noted three "threatening effects" including "rock bursting," "costly and troublesome drainage problems" and the following:

> Construction of the repository at very high in-site temperatures, estimated by Rockwell to be 57^{o}C but possibly considerably higher. Refrigeration on a scale seldom if ever attempted in world mining may be necessary. **The costs in time, money, energy, and lives of men are likely to be very high.**

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[34] See Nevada timeline 1999
[35] NRC 2008, p. 59555.
[36] 10 CFR 51.1 2008

> **Even if each of the above [threatening effects] is individually tractable, all in combination may be intolerable.** More satisfactory alternatives probably can be found elsewhere.[37]

The DOE ignored this 1983 analysis and went ahead and selected basalt at Hanford as one of the top three sites it would characterize.

In the case of granite, the medium in which DOE hoped to find second repository locations for characterization, the DOE proceeded with a screening program that was so technically deficient that the ranking results were not credible. Essentially, the scoring system adopted by the DOE in its Delphi consultation gave zero weight to criteria for which no information was available. This made them equivalent to criteria which were "unimportant" or "judged to be poorly measured." In other words, if the DOE did not know anything about it then it could be ignored. As a result, the sites for which the least was known would tend be ranked higher than those about which there were more data and adverse as well as positive or partly positive characteristics could be evaluated. In other words, the DOE essentially used an "ignorance is bliss" approach to site ranking in order to determine which sites it would characterize."[38] The second repository program was abandoned in 1986.

We may also cite the example of France in regard to performance, which has the second largest number of reactors of any country in the world (after the United States) and which has a repository program that has been attempting to characterize a site. We have already noted that the program's research in regard to seals and thermal effects is deficient in certain critical aspects. We note here than ANDRA, the French agency charged with repository characterization and development, itself had found that doses would be greatly exceeded in the event of a seal failure. Calculated peak doses in that scenario due to chlorine-36 in Class B waste (the approximate equivalent of U.S. Greater Than Class C waste) would be 300 millirem per year and those from due to iodine-129 in spent fuel would be 1,500 millirem per year.[39] Both of these are greatly in excess of the French limit of 25 millirem per year and even of the more lax U.S. final EPA standard for Yucca Mountain of 100 millirem per year beyond 10,000 years.

These examples illustrate that it is essential to take into account the specific aspects of repository research that are important to assessing whether a given disposal system can perform to specified standards for health and environmental protection.

With the exception of salt sites, which the NRC itself rejects for spent fuel, the NRC has failed to take the specific scientific evidence about the U.S. repository program and the potential for it to meet performance, safety, and health criteria for protecting public health, worker safety, and the environment into account. By failing to examine the available evidence in regard to the elements of a repository system relevant to the United

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[37] White 1983, p. 25, reprinted as an appendix to Makhijani and Tucker 1984, emphasis added.
[38] See Makhijani 1986
[39] ANDRA 2001, p. 139.

States, the NRC has not met the minimal requirements of a scientifically based analysis that is necessary to arrive at a conclusion that there is "reasonable assurance" that safe disposal of spent fuel in a repository is technically feasible.

We are not persuaded by the NRC appeal to the fact that 24 countries have repository programs..[40] The fact that all countries with nuclear power programs have to deal with the intractable problem of nuclear waste and have chosen to believe that disposing it of in deep underground will solve the problem is not a scientific demonstration of technical feasibility of safe disposal of nuclear spent fuel in a geologic repository. In its Waste Confidence Decision Update, the NRC has used information from other countries to argue the unexceptionable point that social and political factors are important. The fact remains that no country has a repository for spent fuel or even high-level waste disposal. Further, the NRC has not presented technical evidence from the many repository programs to show that there are enough data for each of the three elements described above – the waste and waste packages, the back fill and sealing system, and the near- and far-field environment – in these programs to come to a reasonable conclusion that each is sound and that they will function together as modeled with reasonable assurance. Nor has it presented any scientific analysis of how these programs are technically relevant to the specific conditions in the United States in terms of assisting the NRC's ability to buttress Finding 1 in regard to the three elements and the modeling of their functioning together.

By contrast, we have shown that the U.S. Yucca Mountain site may well not meet established radiation protection norms and may even be fatally flawed. The geologic setting is not likely to play a significant role in containment of radionuclides, even according to the DOE's own assessment. Among other things, the basalt site at Hanford presents severe safety issues, which the NRC did not address. The second round repository investigation for granite sites in the United States was a failure, for a variety of reasons.

IEER's detailed review of the French repository program research indicated that the research was significantly deficient in certain critical areas – seals and thermal perturbation modeling. And we have shown that ANDRA's own estimates of doses in case of failure of seals would result in doses that would greatly exceed both French and U.S. disposal standards. The NRC itself has deemed salt unsuitable for spent fuel. Yet it did not explore the implications of that conclusion for the Waste Confidence Decision Update or for its reactor licensing program (see Section C below). The NRC mentions that the German salt dome repository program at Gorleben was suspended "[a]fter decades of intense discussions and protests,"[41] but mentioned none of the adverse technical factors that made the choice of Gorleben controversial or the fatal accident that occurred in 1987.[42]

[40] NRC 2008, p. 59559.
[41] NRC 2008, p. 59559.
[42] For a discussion of some of the technical factors and the accident see Franke and Makhijani 1987.

3. Conclusions regarding Finding 1

In sum, in reiterating Finding 1, the NRC has not taken into account a mountain of data and analysis that are relevant to it that show that it is far from assured that safe disposal of spent fuel in a geologic repository is technically feasible. The NRC has not met either of the criteria we set forth at the beginning of this section for assessing whether there was reasonable assurance that safe disposal is technically feasible. In the absence of data from a repository that has been sealed after spent fuel has actually been disposed of – and such data does not exist because no such repository exists – the NRC must provide data on and analysis of the major elements of a site that could be developed in the United States and show that the three elements required in any repository system would work together satisfactorily (i.e., meet radiation protection standards) and that such a repository could be safely built. The NRC has not done this. It has not evaluated the severe problems that the U.S. repository program has encountered and the many twists and turns that rules and regulations have taken as a result, notably with respect to Yucca Mountain. Indeed, the NRC has provided no scientific evidence in its Draft Decision that there is reasonable assurance in the scientific and statistical sense of the term that there is reasonable assurance safe disposal of spent fuel in a geologic repository is technically feasible.

In view of the above, we conclude that the NRC's Finding 1 should be modified. This is necessary on its own, but it is especially necessary in view of the fact that Finding 2 depends on Finding 1. We recommend that Finding 1 be modified to read:

1. While some of the elements of deep geologic disposal have been studied to a sufficient degree that they may be viable elements of a disposal system, an entire thermally and mechanically perturbed system has never been tested. The data on the individual elements of the perturbed and sealed system and for their combined functioning are not yet sufficient to determine the performance of a repository for safe spent fuel disposal with reasonable assurance.
2. The DOE has been pursuing study and characterization of repositories for decades and essential technical questions in relation to performance continue to be in doubt. Under some circumstances, the impact of disposing of spent fuel in a geologic repository could be significant.
3. Considerable further work remains to be done before there can be reasonable assurance that safe disposal of spent fuel and high-level waste in a deep geologic repository in the United States is technically feasible.

We have also concluded that a new generic environmental impact statement is needed to address the fundamental deficiencies of Table S-3. Licenses for new reactors and extension of licenses of existing reactors cannot be properly granted on the basis of the existing Table S-3.

B. Comments on Proposed Finding 2

The proposed Finding 2 states:

> The Commission finds reasonable assurance that sufficient mined geologic repository capacity can reasonably be expected to be available within 50–60 years beyond the licensed life for operation (which may include the term of a revised or renewed license) of any reactor to dispose of the commercial HLW and spent fuel originating in such reactor and generated up to that time.[43]

The NRC has made an unwarranted leap from its "Finding 1"[44] that a geologic repository for disposal of high-level waste and spent fuel is technically feasible to the conclusion that there is "reasonable assurance" of the actual availability of a repository within 50 or 60 years beyond the operating license of any commercial reactor in the United States.

In order to proceed from a finding that a geologic repository is technically feasible to the conclusion that one will be available within a specified time frame (in this case ~100 to 150 years), at least three additional demonstration elements are necessary. First, it must be shown that the requisite work of finding, characterizing, licensing and developing an actual site suitable for disposal of the actual amounts of waste to be generated is possible within the stipulated time. Second, a demonstration of financial feasibility and reasonableness is needed. And thirdly, a demonstration of political and social acceptability is also necessary. We will consider this last question first.

1. Social and Political Acceptability

The NRC has provided a survey of various country programs in order to review the issue of social and political acceptability.[45] This survey itself shows that there can be no confidence that the necessary social and political conditions exist in the United States to provide any assurance that a repository can be developed in any foreseeable time frame. Second, the NRC's survey is partly inaccurate. Third, the NRC's survey is essentially incomplete in that it omits the country that is often held up as being exemplary for nuclear power – France.

We discuss the NRC's survey before proceeding to the specific discussion of the situation in the United States.

1. *United Kingdom:*

The NRC appears to believe that the United Kingdom had a repository program for high level waste and spent nuclear fuel in the 1990s. Specifically the draft rule states the following

[43] NRC 2008, p. 59561.
[44] NRC 2008, p. 59553. See below for comments on Finding 1.
[45] NRC 2008, pp. 59559-59561.

> In the United Kingdom, in 1997, an application for the construction of a rock characterization facility at Sellafield was rejected, leaving the country without a path forward for long-term management or disposal of HLW or SNF. In 1998, an inquiry by the UK House of Lords subsequently endorsed geologic disposal, but specified that public acceptance was required.[46]

The NRC appears to have its facts about the UK repository program wrong. According to a timeline and status report by Alan Hooper of Nirex, Britain's waste management company, the geological investigations for a high-level waste repository were short-lived; they did not involve an application for a rock characterization facility:

- 1976—The Royal Commission on Environmental Pollution (Flower's Report) recommended the creation of a National Waste Disposal Corporation.
- 1979—Start of program of geological investigations for HLW disposal.
- 1981—**Termination of the geological investigations and suspension of a decision on high-level waste disposal for 50 years.**
- 1982—Nuclear Industry Radioactive Waste Executive (NIREX) created to implement Government policy on intermediate-level waste (ILW) and low-level waste (LLW).
- …
- 1987—Abandonment of the near-surface program and adoption of new policy that all ILW and LLW should go deep…; new deep site selection process started.
- …
- 1991—Nirex decides to focus investigations on Sellafield in Cumbria.
- 1992—Nirex announces plans for a Rock Characterisation Facility (RCF) at Sellafield; the plans were eventually considered at a public inquiry which ended in 1996.
- 1997—Decision by Government not to allow Nirex to proceed with the RCF, thus terminating the UK's siting program.[47]

As can be seen, the UK terminated its HLW geologic disposal investigations in 1981. The rock characterization facility to which the NRC refers was for Intermediate Level Waste (similar to Greater Than Class C waste in the United States), which is also mandated for deep geologic disposal. However, the geologic requirements for disposal of ILW are much less stringent than for high-level waste or spent fuel, because the characteristics of these wastes are very different. For instance, the specific activity of high-level waste and spent fuel is generally much higher, as is the heat generation.

The UK formed a Committee on Radioactive Waste Management as a vehicle for public consultation and exploration of the issue of long-term waste management. As the NRC

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[46] NRC 2008, p. 29559.
[47] Hooper 2006, pp. 249- 250. Emphasis added.

noted, the most recent evidence is that this is also failing. According to the draft waste confidence rule:

> This [program] led to the initiation of a national public consultation, and major structural reorganization within the UK program. In 2007, the Scottish Government officially rejected any further consultation with the UK Government on deep geologic disposal of HLW and SNF. Discussions may continue on issues of interim storage only. This action by the Scottish Government effectively ends more than 7 years of consultations with stakeholders from communities near Scottish nuclear installations and represents another major setback for the UK program.[48]

Actually, the Scottish government press release does not mention high-level waste or spent nuclear fuel explicitly, but "higher activity" waste,[49] which includes intermediate level waste in the UK. In point of fact, the UK has no active repository program that is looking at a specific site for high-level waste or spent nuclear fuel and has not had any since 1981.

In other words, even though British nuclear waste authorities may believe that a repository is technically feasible, the program is at a dead end and only interim storage is on the table. So far the public consultation program has failed to elicit any progress towards a high-level waste repository. In the meantime, the decommissioning and clean-up of its main reprocessing site (Sellafield) is estimated to take more than 100 years and costs have skyrocketed to 73 billion pounds (roughly $100 billion).[50] While Sellafield was born as a nuclear weapons materials production site, most of the work there and most of the waste there has been generated in the past few decades from reprocessing of British and (more recently) foreign spent fuel. These costs do not include waste disposal or repository development costs.

2. *Germany*

The German repository program began investigating a salt dome at Gorleben in 1977. Major construction and characterization activities were carried out. The NRC described its status as follows:

> After decades of intense discussions and protests, an agreement was reached in 2000 between the utilities and the government to suspend exploration of Gorleben for at least three, and at most, ten years. In 2003, the Federal Ministry for the Environment set up an interdisciplinary expert group to identify, with public participation, criteria for selecting new candidate sites.[51]

There is as yet no specific site being characterized. After more than three decades, the program is moribund.

[48] NRC 2008, p. 59559.
[49] Scottish Government 2007
[50] Irish Times 2008
[51] NRC 2008, p. 59559-59560.

3. Switzerland

The Swiss have done a quarter century of geologic repository research. In 1998, the Swiss was authorities found that a repository was technically feasible and that it has been successfully demonstrated, the repository was rejected in a referendum in the canton.[52] The Swiss authorities have no firm date for the opening of a repository, but, according to the NRC, they "do not expect [that] a deep geologic repository will be available in their country before 2040."

4. Canada

An independent commission, empanelled by the Canadian government found in 1998 that a geologic repository was technically feasible and that the concept had been sufficiently demonstrated. Yet, public acceptance is not assured. Canadian law requires public consultation. In 2007, Canada adopted an approach of public consultation with communities, which will supposedly be "community-driven" and "collaborative." No site has been selected as yet for characterization. The authorities recognize that the process will take time. According to the NRC, the Canadian waste authority "*assumes* the availability of a deep geological repository in 2035"[53] An assumption is clearly not the same as a reasonable assurance. It simply allows financial calculations to be made. Given that the authorities are still on square-one in regard to public acceptance after 37 years of implementing a program and considerably more than that of nuclear reactor experience, the date of 2035 can only be considered notional. It is not based on an actual program of characterization on the ground or the acceptance of a particular community located at a specific site.

5. Finland

Finland is the only country with an active nuclear power program and an active repository program where the host community government has approved of the repository site and agreed to host it. The opening of the deep repository is expected in 2020.[54]

6. Sweden

Two municipalities in Sweden have agreed to be potential hosts of a geologic repository and an application for repository development is estimated to be filed in 2009.[55] However, it should be noted that Sweden has had a national moratorium on the construction of new nuclear power plants.[56] Therefore, its entire public consultation process has been carried out in the context that the waste stream would be limited to that

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[52] NRC 2008, p. 59560.
[53] Both quotes are from NRC 2008, p. 59560, italics added.
[54] NRC 2008, p. 59560.
[55] NRC 2008, p. 59560.
[56] Lundqvist 2006 p. 227

from its existing reactor fleet. It is an open question whether public acceptability would be forthcoming should Sweden reconsider its moratorium and rescind it.

7. France

The NRC has described the above six cases as part of its discussion of Finding 2 and the proposed update of this finding. It is interesting that the NRC did not discuss the French program (other than a passing mention in a footnote). In fact, the French program has faced serious public opposition and its history is somewhat similar to the one in the United States. The original intent was to characterize more than one site. Only one site, in north-eastern France is being characterized. It has faced considerable local opposition. The selection of a second site (in western France) for characterization was abandoned after serious public opposition.[57] The French appear to be as averse to having high-level nuclear waste in their backyards as people in other countries. Further, as noted above, there are serious technical questions about how ANDRA, the French nuclear waste agency, is proceeding to characterize the site and whether the results will be adequate to provide a satisfactory scientific basis for performance assessment. In other words, the public's skepticism about official technical work may not be misplaced, contrary to the NRC's implication that public and political non-acceptance of a geologic repository is somehow not based in science.[58]

2. Political and Social Acceptance Issues in the United States

Political and social acceptance is as essential in a democracy as technical feasibility. We have already discussed that the NRC has not provided the basis for its finding that there is reasonable assurance that a repository is technically feasible. We discuss here the social and political aspects of feasibility, which are also important for estimating a schedule. The NRC now acknowledges that in developing a repository schedule:

> The Commission's proposed revision of Finding 2 is based on its assessment not only of our understanding of the technical issues involved, but also **predictions of the time needed** to bring about the necessary societal and political acceptance for a repository site.[59]

The U.S. program has been beset with difficulties that are well known. Some of them are described in the discussion of the proposed update to the NRC's waste confidence findings. Some others have been discussed above. The failure of the second repository program provides another example. It was, in large measure, due to public opposition; but at least some of that opposition was technically well-founded since there were many technical problems with the approach that the DOE used to select the sites in its Draft

[57] CNE 2001, pp. 53-55.
[58] The proposed waste confidence rule states "International developments have made clear that technical experience and confidence in geologic disposal, on their own, have not sufficed to bring about the broader societal and political acceptance needed to realize the authorization of a single national repository." NRC 2008, p. 59559.
[59] NRC 2008, p. 59561, emphasis added.

Area Recommendation Report. (An unscientific element in the DOE's approach to site ranking, an essential technical element of site section, is briefly discussed above as an example of the problems in the report). The narrowing of site characterization to one site in Nevada was also political. As discussed above and below, the Yucca Mountain site has characteristics that make it unsuitable for a repository. But in the present context of a discussion of the proposed revision to Finding 2, it is sufficient to note that the State of Nevada and its representatives have been vigorously opposed to it on a bipartisan basis. Further, the political position of those representatives is considerably stronger today than it was when the 1987 amendments to the 1982 Nuclear Waste Policy Act (NWPA) were passed. Senator Harry Reid of Nevada is now Majority Leader of the U.S. Senate.

The Yucca Mountain Project also faces serious budgetary constraints. DOE's announced timetable of an opening by 2020 is contingent on Congressional appropriations. There is no basis in present political reality to assume that the DOE would get what it wants for site development. The United States program is also mired in litigation. Though a final EPA standard has been issued, it is not a given that it will hold up in the courts or that the Yucca Mountain site can meet the limits that the EPA has set.

The vigorous opposition of the people of Nevada and also of many along the transportation routes to Nevada is a fact that does not bode well for the eventual operation of the Yucca Mountain repository. Only one repository program is proceeding with a specific site where a repository may be assumed to open with reasonable assurance. That is the Finnish program, which was undertaken with both national and local approval. There is no other repository program that is on a road that would allow a conclusion that a repository would open with "reasonable assurance." Indeed, the NRC's revision of Finding 2 is not now dependent on the opening of Yucca Mountain, but on the opening of some repository within 50 to 60 years of the termination of the license of any operating reactor.[60]

We now have a President of the United States who is on the record as having stated that the Yucca Mountain site is unsuitable. President Obama has written:

> I want every Nevadan to know that I have always opposed using Yucca Mountain as a nuclear waste repository, and I want to explain the many reasons why I've held that view.
>
> In my state of Illinois, we have faced our own issues of nuclear waste management. There are some who believe that Illinois should serve as a repository for nuclear waste from other states. My view on this subject was made clear in a 2006 letter to Sen. Pete Domenici, who at the time was chairman of the Senate Energy Committee. "States should not be unfairly burdened with waste from other states," I wrote. "Every state should be afforded the opportunity to chart a course that addresses its own interim waste storage in a manner that makes sense for that state."
>
> That is a position I hold to this day when it comes to both Illinois and Nevada.

[60] NRC 2008, p. 59558 and p. 59561.

> After spending billions of dollars on the Yucca Mountain Project, there are still significant questions about whether nuclear waste can be safely stored there. I believe a better short-term solution is to store nuclear waste on-site at the reactors where it is produced, or at a designated facility in the state where it is produced, until we find a safe, long-term disposal solution that is based on sound science.
>
> In the meantime, I believe all spending on Yucca Mountain should be redirected to other uses, such as improving the safety and security of spent fuel at plant sites around the country and exploring other long-term disposal options.[61]

But if Yucca Mountain fails, it is not at all evident that a second program could be successfully put into place, as the NRC assumes. Besides the repeated delays, cost overruns, and technical problems that have plagued the Yucca Mountain program, there are other historical facts that need to be taken into account here. For instance, the DOE's Nuclear Waste Negotiator program, which aimed to find a community by consent, was eventually a failure. President George H.W. Bush appointed David H. Leroy as the Nuclear Waste Negotiator in 1990.[62]

Some attempts to locate a "temporary storage" facility at Native American reservations failed outright. The Private Fuel Storage proposed for Goshute reservation in Utah has also essentially failed, despite approval by the NRC, because of state opposition and opposition of people within the Goshute tribe to a tribal council decision to host it. A legal challenge remains.[63] It is highly unlikely that PFS will get to use the license that the NRC has granted it.

There is nothing in the history of the U.S. high-level waste program, from the first characterization program near the Lyons, Kansas, site in the 1960s to the Yucca Mountain site in 2009 that encourages the view that a repository would gain state approval. In its discussion of Finding 2, the NRC itself has acknowledged that "technical experience and confidence" are not enough to create a successful repository program:

> It is important to note, however, that broader institutional issues have emerged since 1990 that bear on the time it takes to implement geologic disposal. International developments have made clear that technical experience and confidence in geologic disposal, on their own, have not sufficed to bring about the broader societal and political acceptance needed to realize the authorization of a single national repository.[64]

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[61] Obama 2007
[62] Wald 1991
[63] Two agencies of the Department of the Interior have issued decisions effectively ending the proposed Private Fuel Storage facility. See BIA 2006 and BLM 2006. Discussion of the opposition to the PFS in Nevada can be found at http://deseretnews.com/article/content/mobile/1,5620,645199671,00.html?printView=true and at http://healutah.org/nuclearutah/waste/pfs, among other sources. Not all challenges have ended. In July 2007, Private Fuel Storage made a claim against the Department of the Interior, hoping to reverse the decision. See NRC 2008, p. 59566 (footnote 24) – the claim has not been settled.
[64] NRC 2008, p. 59559.

The entire history of the program, from Lyons Kansas, to the second round repository sites, to PFS, to the continuing legal, technical, and political challenges to Yucca Mountain, including now from the President of the United States, lends support to the view that both state and local consent are necessary (and consent of the people and governments of the tribes in the case of Native Americans) in the United States to the opening of a spent fuel repository.[65] With this history and with the strong U.S. tradition of state political prerogatives and rights, a statement that there is "reasonable assurance" that a repository would open in the foreseeable future without both state and local consent is unwarranted and unjustified. This conclusion would stand even if Yucca Mountain were a technically suitable site. And, as discussed above, there are many indications that Yucca Mountain is not a technically suitable site.

Yucca Mountain could not even accommodate spent fuel from existing reactors without new legislation, much less spent fuel from any new reactors that might be built. A second repository would also require new legislation and, as the proposed update acknowledges, it may require new NRC regulations.[66] There needs to be reasonable assurance that workable legislation would be passed before the NRC can conclude that there is "reasonable assurance" that a repository will be available in some general time frame. To fail to provide a basis for assuming that there would be such legislation is to fail to provide a satisfactory basis for the central claim in the proposed Finding 2.

The NRC stated in its Draft Waste Confidence rule that its revision of Finding 2 is based in part on "**predictions of the time needed** to bring about the necessary societal and political acceptance for a repository site."[67] But the NRC has not provided any political, historical, legislative, or social fact, much less an analysis, to support its prediction that that there will be sufficient political or societal support for a repository by 50 to 60 years after the license of any reactor has expired. Under the present circumstances, with opposition from the President of the United States and from the Majority Leader of the U.S. Senate, it is reasonable to conclude that the Yucca Mountain project will sputter along with inadequate funds or be ended entirely.

In the absence of action to lift the 70,000 metric ton cap, legislation to authorize a second repository is needed. Moreover, such legislation should be workable. The history of nuclear waste programs around the world indicates that state, local, and (when applicable) tribal consent is one essential ingredient of a successful program (though by no means the only one). Further, the federal government must be of one mind in pursuing the project over a long period of time. The history of the NWPA shows that not one of these societal and political conditions has been met. There is no indication in political reality that they will be met. The history of the second repository, which was abandoned in 1986, and the Nuclear Waste Negotiator program also points in the same direction.

[65] This does not mean state and local support would be sufficient; it is just one necessary condition. Technical, legal, environmental and health criteria also needed to be satisfied.
[66] See footnote 3, NRC 2008, p. 59555.
[67] NRC 2008, p. 59561, emphasis added.

Even though it recognizes the important of social and political factors, the NRC proposes to find that there is reasonable assurance that there will be a repository any underlying legislative or political feasibility analysis. In effect, the NRC is assuming that the Executive Branch of government can confront the Legislative Branch with a *fait accompli* of granting license extensions to existing reactor licensees and licenses to new applicants. The implicit assumption is that Congress must then act to create a repository program that will accommodate all the waste and that new legislation will actually result in a repository.

The NRC apparently recognizes the weakness of its position regarding Finding 2 in that it explicitly solicits comment as to whether it should find instead that storage on site is safe "until a disposal facility can reasonably be expected to be available."[68] There is even less reasonableness in punting to the indefinite future, when the uncertainties and risks become greater. A large part of the very notion of spent fuel disposal is that it is far too risky to leave spent fuel lying around at dozens of sites for the indefinite future. This matter cannot be settled within the framework of dates or simply indefinite deferral of decisions. After repeatedly incorrect Waste Confidence Decisions regarding reasonable assurance of repository availability, the reasonable thing now is to do an Environmental Impact Statement that properly considers all the alternatives. This is necessary in any case, since a large part of the environmental impact evaluation done in the reactor licensing process is either obsolete or wrong or both (see below).

3. Financial considerations

There is also no fiscal or economic basis for concluding that there is a reasonable assurance that a repository will be available. The Nuclear Waste Policy Act requires nuclear utilities to collect 0.1 cents per kilowatt-hour from ratepayers and provide them to the federal government for spent fuel disposal in a repository. Annual nuclear electricity generation was about 787 billion kWh in 2006,[69] making that year's contribution to the Nuclear Waste Fund of about 787 million dollars. About 56,000 metric tons of spent fuel have already been generated as of April 2008. The figure is expected to rise to 119,000 metric tons by 2035.[70] However, reactor relicensing is continuing so this quantity is likely to increase, for instance, if nearly all operating reactors are relicensed.

In addition, the geologic repository must also accommodate Department of Energy reprocessing high-level waste disposal. As discussed above, it is highly unlikely that the 70,000 metric ton cap for the Yucca Mountain site will be lifted by Congress. The financial consequences of these facts must be taken into account in any waste confidence ruling dealing with both existing and new reactors.

The DOE's cost estimate for Yucca Mountain has escalated from about 57.5 billion dollars in 2001 to 96 billion dollars in 2008 for a variety of reasons, including more waste

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[68] NRC 2008, p. 59561.
[69] Data from the U.S. Energy Information Administration (DOE EIA 2009)
[70] DOE OCRWM 2008.

and inflation.[71] This estimate is based on a smooth functioning of the program from here on out. This is highly unlikely given that program funds are highly likely to be cut, if it is not terminated altogether. It would be prudent and reasonable to assume that the costs of Yucca Mountain likely to be well over $100 billion, if it opens. At 0.1 cent per kWh, and 90 percent capacity factor for 60 years, the present U.S. reactor fleet will generate about $50 billion in revenue.[72] Moreover, this revenue is in current dollars, since the fee is not adjusted for inflation. But the costs are subject to inflation, one reason that they keep going up with every delay. Note that the cost estimate of $96 billion is in constant 2007 dollars. While there is some additional revenue from DOE defense high-level waste and some revenue from interest, this is unlikely to keep pace with rising costs.

It is not reasonable to assume that the present 0.1 cent per kWh fee will suffice to pay for the U.S. repository program. Further, given the political and legislative situation and the history of Nevada's opposition to Yucca Mountain, it is not reasonable to assume that the 70,000 metric ton cap will be lifted. Hence a second repository may well be necessary to accommodate spent fuel from existing reactors, and the problem will be worse if most or all of the reactors are relicensed. This would be true even if no new reactors are built.

There is at present no way to estimate the costs of a second repository, since the cost escalations for the first have been large and the program may fail altogether for one or more of a variety of reasons. In the interim, governmental liabilities for failing to meet its statutory deadline for beginning the process of taking ownership and disposing of the spent fuel are mounting. With no reasonable date for Yucca Mountain or a second repository in sight, the government's liabilities may become huge and must be taken into account in the overall cost of spent fuel storage and disposal. The penalty costs cannot at present be charged to ratepayers, since the government is in contractual default. The costs are nonetheless real to the people of the United States as a whole and much of the money is coming from ratepayers via federal taxes, and the rest from other taxpayers who are not now consuming nuclear electricity.

The NRC needs to address the financial uncertainties, legislative difficulties, and other political and social problems in making its estimate of the time in which a repository might become available. While political situations are subject to change, there is nothing in the past that encourages the view that it is becoming easier to find political acceptance for a repository in any part of the country.

In view of the above, the Institute for Energy and Environmental Research makes the following recommendations regarding the update of Finding 2. This finding should be change to explicitly state that:

1. It is far from assured that a second repository site can be successfully opened in the United States without the acceptance of the host state and local community.

[71] DOE 2008b
[72] Some of this has already been generated, of course, since ratepayers have been paying into the fund for the past quarter of a century.

Such acceptance may or may not be forthcoming. The history of the U.S. repository program is not encouraging in this regard.

2. It is far from assured that the cap of 70,000 metric tons of heavy metal that is imposed by the Nuclear Waste Policy Act will be lifted.
3. In view of 1 and 2 above, commercial nuclear reactor licensees should make financial, security, and technical provisions for indefinite, secure, and hardened storage of spent fuel at reactor sites. These provisions should include infrastructure for transferring spent fuel bundles from one dry cask to another.
4. In view of 1, 2, and 3 above a generic EIS on spent fuel management and disposal including the alternatives mentioned above needs to be prepared, along with cost estimates and estimates of comparative security risks.

C. Requirements for a Generic Environmental Impact Statement on Spent Fuel Waste Confidence

The Waste Confidence Decision Update is being proposed in the context of NRC relicensing reactors in the existing fleet and of the applications for licenses for new reactors that it is considering. This update has major implications for safety and environmental impact. It will commit generations far into the future to potential harm if the NRC does not properly consider all relevant aspects of "safe disposal" and of environmental and health impacts of the wastes and radioactivity releases associated with reactor operations.

1. Need for a Generic EIS on Waste and Reactor-Related Emissions

As set forth in Section A above, the NRC has not presented a scientific analysis to support its claim that there is "reasonable assurance" that "safe disposal" of spent fuel in a geologic repository is "technically feasible" (Finding 1) or that it can be opened within the time frame set forth in the proposed revision of Finding 2. On the contrary, it far from assured that such safe disposal is technically feasible. It is important to note in this context that the prior Commission bases, on which its earlier findings were based, have been invalidated by experience, time, and new scientific understandings, many of which have been discussed above. Consider Yucca Mountain, which should provide the strongest case for a technical feasibility determination. Deadlines have repeatedly slipped. New data on corrosion have emerged. Some experts have deemed this site as inadequate and even "fatally flawed.' Most of the DOE dose estimates made since 1990 show exposures in excess of the current EPA standard of 100 millirem beyond 10,000 years. As a result, there is considerable scientific basis to doubt that Yucca Mountain is a suitable repository or that it should be licensed. We have discussed a critical problem with DOE's license application in that it sidestepped a key recommendation of the NWTRB by declaring it insignificant. There is also no real basis to estimate a future time, either as a date or in relation to expiry of reactor licenses, when there can be reasonable assurance that a repository can be opened.

The escalation of costs without an actual result in the form of a repository as well as the escalation of penalties for the government's failure to begin disposing of existing wastes

is causing waste management costs to escalate well beyond what was projected when the program was put into place. There is no clear current cost estimate of what it will cost to dispose of all the spent fuel currently scheduled to be produced from existing licenses and license extensions that have already been granted. This means that it is impossible to make a reasonable comparison with alternatives methods of electricity production that do no involve the creation of long-lived radioactive waste such as spent fuel and Greater Than Class C waste and depleted uranium.

In view of these facts, it is essential for the NRC to prepare a thorough generic environmental impact statement on spent fuel that would be generated by new reactors as well as from relicensing of existing reactors.

The NRC also needs a current and coherent analysis of the health impacts of the nuclear waste that will be created incident to the licensing of new nuclear plants and re-licensing of existing nuclear plants. The need for such a statement is further demonstrated by the fact that much of the basis for the assessment of the environmental impacts of reactor operation, which is part of the reactor licensing process, is obsolete and/or wrong. Specifically, Table S-3 at 10 CFR 51.51, is obsolete or incorrect in many respects, especially in regard to assumptions about the impacts of disposal of spent fuel, Greater than Class C Waste, Depleted Uranium as well as about other impacts (see below). Since the NRC is now engaged in a sweeping process, via relicensing existing reactors and considering new reactor licensees, to allow the creation of vast amounts of new waste, a generic EIS is needed.

Finally, the prior EIS on geologic disposal, prepared by the DOE is, like Table S-3, hopelessly out of date and also incorrect in essential parts about its estimates of environmental and health impacts.

No pre-existing EIS, already prepared by the NRC or the U.S. Department of Energy ("DOE"), is sufficient to support the Waste Confidence Decision. For instance, the EIS prepared by the DOE in 1980 is insufficient in scope and grossly out of date. As one example, the DOE EIS does not anticipate any releases from a properly constructed repository in the absence of extraordinary and rare events. In fact, it stated that there was "every expectation that long-term radiological impacts will be nonexistent."[73] As discussed at length above, this is contrary to present understanding of any medium but salt, which the NRC itself now says is unsuitable for spent fuel disposal.

As another example, the DOE did not even examine a repository in tuff, which is the rock at Yucca Mountain and has been the only repository being characterized since 1987. It was written before there was an adequate understanding of the complexities of the three elements of the disposal system, discussed above in Section A, and the difficulties of estimating their joint performance. For instance, at the time, containers were expected to perform the role of a barrier for the early period of disposal, while the geologic system would take care of the long-term:

[73] DOE 1980, p. 5.72. The DOE only considered long-term radiological releases in case of improbable events such as meteorite impacts

> The multiple barriers that could contain nuclear waste in deep mined repositories fall into two categories: 1) geologic or natural barriers and 2) engineered barriers. Geologic barriers are expected to provide isolation of the waste for at least 10,000 years after the waste is emplaced in a repository and probably will provide isolation for millenia [sic] thereafter. Engineered barriers are those designed to assure total containment of the waste within the disposal package *during an initial period* during which most of the intermediate-lived fission products decay. This time period might be as long as 1,000 years…[74]

It is clear that when DOE prepared this EIS in 1980, engineered barriers, including containers, were not expected to fulfill the main long-term function of containment for 10,000 years or more. But the NRC now only requires only an overall performance assessment which combines the performance of all elements together and does not put any sublimits on the performance of any particular element. As we have noted in Section A, in the case of Yucca Mountain, the essential performance burden in the sense of compliance with regulations rests with the containers. Indeed, the NRC's rules in this regard have also changed since the DOE's EIS was issued. The NRC's first rules corresponded more to the DOE's EIS concept that engineered barriers were to contain the waste in an initial period with the geology taking up the function after that. Those rules, which apply to geologic repositories to be licensed by the NRC, are at 10 CFR 60, but they Yucca Mountain was exempted from them, just as it was exempted from 40 CFR 191, Subpart B, which applies to all other repositories. 10 CFR 63, which requires only a combined performance assessment, was promulgated specially for Yucca Mountain.

Finally, a central part of licensing of new reactors and of the relicensing of existing reactors is as it concerns light water reactors (that is, all licensed power reactors in the United States) is the requirement that the license applicant prepare an Environmental Report that addresses:

> Table S-3, Table of Uranium Fuel Cycle Environmental Data, as the basis for evaluating the contribution of the environmental effects of uranium mining and milling, the production of uranium hexafluoride, isotopic enrichment, fuel fabrication, reprocessing of irradiated fuel, transportation of radioactive materials, and management of low level wastes and high level wastes related to uranium fuel cycle activities to the environmental costs of licensing the nuclear power reactor.[75]

In the sections below we show that Table S-3 is obsolete and incorrect in a number of critical areas and needs revision, correction, and updating.[76] Since this is the main vehicle for assessing the environmental impacts of nuclear energy, a revision of this table and of the corresponding parts of 10 CFR 51, needs to be a part of the generic EIS on waste and the environmental impacts of nuclear energy.

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[74] DOE 1980, p. 5.1

[75] 10 CFR 51.51(e) 2008. [N.B.: formerly 51.20(e) 1984]

[76] The comments below on Table S-3 apply as well to Table S-3A, which is in WASH-1248 and provides more detail for Table S-3, when applicable.

2. Solid high-level waste and spent fuel disposal impacts

This requirement applies to "any applicant's environmental report submitted on September 4, 1979, or thereafter."[77] In regard to high-level waste or spent fuel, Table S-3 purports to provide environmental impacts that "are maximized to either of the two fuel cycles (uranium only and no recycle)."[78] While this purports to be the maximum impact from spent fuel disposal (either with or without reprocessing), the claim is either wrong, obsolete, or both.

First, the Nuclear Waste Policy Act envisions disposal of spent fuel. The reprocessing impact calculations are therefore irrelevant for present licensing and environmental impact considerations. Second, the Statements of Consideration associated with the promulgation of the final rule effective on September 4, 1979, explain the regulation note the following in regard to storage and disposal as follows:

> In determining the impacts associated with waste management and disposal, the [Nuclear Regulatory Commission] staff assumed that high-level waste (or reactor spent fuel treated as waste) would be stored in interim facilities (water basins and retrievable surface storage facilities) for about twenty years and then disposed of by burial in a bedded salt repository.[79]

In a footnote to this passage, the NRC noted that the original rulemaking had not extensively covered deep geologic disposal but subsequent work, published in NUREG-0116 has remedied that problem:

> …NUREG-0116, Section 4.4, provides a 30-page quantitative discussion of disposal of long-lived wastes in a bedded salt repository, with citations to many relevant technical documents prepared since 1973. [80]

Thus, in 1979, the NRC had considered bedded salt as suitable for disposal either of reprocessed high-level waste or unreprocessed spent fuel. Yet, the draft waste confidence rule of 2008 states that salt formations are not being considered for spent fuel disposal for technical reasons (see quote above). Hence, Table S-3 is completely outdated and inappropriate according to current law, which requires spent fuel disposal, and the NRC's own understanding of salt repositories.

To wit, disposal in salt, which is the basis for estimating the environmental impact of high-level waste or spent fuel disposal, is only considered suitable for high-level waste resulting from reprocessing, but reprocessing is not the current policy. Rather, direct disposal of spent fuel, for which the NRC would not consider salt formation, is now the current policy.

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[77] 10 CFR 51.51(e) 2008.
[78] 10 CFR 51.51 2008, Table S-3, Footnote 1. Uranium only means a reprocessing cycle in which only the recovered uranium is reused as a fuel.
[79] NRC 1979
[80] NRC 1979, footnote 19

Moreover, Table S-3 assumes that there will be no releases whatsoever from solid high-level waste disposal.[81] According to WASH-1248, which is the underlying document developed for promulgating the rule:

> The most significant solid radiological waste consists of the fission products separated from the spent fuel of an annual fuel requirement in the reprocessing operation. These high level wastes will be stored onsite for a maximum of 10 yrs., and will ultimately be shipped, probably by rail, to a Retrievable Surface Storage Facility (RSSF). The RSSF will be established to store and manage high level solid wastes under constant surveillance for up to 100 years, or until such time as a more permanent Federal repository can be established. The facility will be designed to prevent the release of significant amounts of radioactive material to the environment under all credible environmental conditions and human actions. *Therefore, such waste will not be released as effluents to the environment.*[82]

The same assumption of essentially zero release and zero impact has evidently been applied to spent fuel as well. The NRC's 1981 background information on Table S-3 affirms this as well:

> It has been assumed that a geologic repository will be designed and operated so as to retain solid radioactive waste indefinitely.[83]

And again:

> The high-level radioactive waste from the once-through fuel cycle is the spent fuel assemblies, which will be packaged and disposed of in a geologic repository. The radioactive waste from the uranium-only recycle option consists of the fuel assembly hulls, the high-level and intermediate-level wastes from reprocessing, and the plutonium waste. These wastes will be disposed of in a geologic repository in the form of solids which will have chemical and physical properties that mitigate the release of radionuclides to the environs. It is assumed that *the geologic repository will be designed and operated so that the solid radioactive wastes are confined indefinitely.*[84]

Table S-3 does not show any releases from a deep geologic repository though ten million curies per reactor-year would be disposed of. Nor are any adverse health impacts estimated. Of course, these are implicitly zero as well, corresponding to the assumed zero release of radionuclides from the repository.

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[81] Table S-3 was revised in 1979 when 10 CFR 51 was promulgated. It has not been changed since. The references to Table S-3 are from 10 CFR 51 as it currently stands and to Table S-3A in so far as it is compatible with the present Table S-3.
[82] WASH-1248, p. S-23, italics added.
[83] NRC 1981
[84] NRC 1981, p. 13, italics added.

In 1983, the Supreme Court affirmed the reasonableness of the zero releases assumed in Table S-3 (BG&E v. NRDC, 462 U.S. 87). This decision was rendered in the context of the assumption of disposal of reprocessing high-level waste or spent fuel in a bedded salt repository. As noted above, the assumption of disposal of reprocessing waste from commercial spent fuel is obsolete; current law requires disposal of spent fuel. There is no commercial reprocessing facility in the United States. The assumption of disposal of spent fuel in salt has been is no longer scientifically supportable due to the thermo-mechanical properties of salt. The NRC itself has concluded that only reprocessing high-level waste is suitable for disposal in salt. Further, the assumption of zero release of radioactivity due to disposal of spent fuel is contrary to the established scientific understanding of the expected performance of all other geologic settings. For instance, all of the DOE documents cited above as well as the graphs shown in Attachment A to these comments show positive doses due to disposal of spent fuel in Yucca Mountain. Of course, positive doses can only be the result of positive releases of radionuclides into the human environment. As far back as 1983, the report on geologic isolation prepared for the DOE by the National Research Council concluded that radiation doses would be positive doses for spent fuel and high level reprocessing waste disposal in all settings other than salt that were evaluated – tuff, granite, and basalt.[85]

The Supreme Court's 1983 finding that an assumption of zero release from high-level waste or spent fuel disposal has therefore been rendered obsolete by the combination of following three considerations:

1. The Nuclear Waste Policy Act requires the disposal of waste from commercial nuclear power plants in the form of spent fuel rather than reprocessing waste.
2. Spent fuel cannot be safely disposed of in a salt repository, as acknowledged by the NRC (see above)
3. All other repository settings are now acknowledged to have some releases of radioactivity.

10 CFR 51 therefore is no longer valid and as the basis for determining the environmental performance of nuclear power plants so far as releases from spent fuel are concerned. As a result it does not provide a satisfactory basis for licensing new nuclear power plants or relicensing existing ones. It also does not provide the basis for confidence that a suitable repository will be available that will keep the environmental impacts within the limits assumed by Table S-3.

Instead of addressing the substantive issues that it faces in regard to waste confidence in the licensing of new reactors or the relicensing of existing reactors under the technical and legal conditions that exist today, the NRC has wrongly assumed the problem away in its draft waste confidence findings by implicitly assuming that Table S-3 is still valid. A new and valid estimate of the set of environmental impacts from high-level waste and

[85] NAS-NRC 1983, Chapter 9. Estimates of doses from spent fuel disposal are only presented for basalt along with the statement that the conclusions for basalt "will apply as well to the other repository media." p. 282.

spent fuel disposal is evidently needed as part of any waste confidence rule. A generic environmental impact statement is needed in order to establish the basis on which new reactors can be licensed or existing reactors can be relicensed.

We note here that there are other parts of Table S-3 that is obsolete or wrong or both that do not concern high-level waste or spent fuel, but relate to the impacts from other parts of the fuel cycle. These also needed to be covered in the new, generic environmental impact statement. Some additional requirements for revision of Table S-3 are discussed in below.

As noted above, Table S-3 is either incorrect or obsolete or both in regard to high-level waste and spent fuel disposal in a geologic repository. There are other ways in which these tables do not properly or adequately assess the impact of wastes and effluents associated with nuclear reactor operation. A thorough revision of these tables and the associated analysis is necessary to correct them and to assess the environmental impact from relicensing existing commercial reactors or licensing new reactors, both of which will result in the generation of large amounts of new waste and radioactivity. We will first cover the ways in which Table S-3 is deficient in matters other than high-level waste and spent nuclear fuel disposal. Then we will provide recommendations for the scope of the generic environmental impact statement that is needed to address those aspects of environmental and health impacts of reactor licensing and re-licensing.

3. Releases of volatile radionuclides from spent fuel

Volatile radionuclides are mainly released to the atmosphere from spent fuel when it is reprocessed if not captured.[86] For instance, iodine-129 would be released to the atmosphere in this way, if not captured. There are also liquid effluents as a result of reprocessing.

In constructing Table S-3, the NRC assumed that I-129 would be released to the atmosphere prior to spent fuel disposal in a repository even though, physically this would not occur. The NRC claimed that this was a "conservative" assumption:

> For spent fuel disposal the staff made the conservative assumption that fission-product gases in the spent fuel, including all tritium, krypton-85, carbon-14, and iodine-129, would be released during handling and emplacement of the waste prior to sealing of the repository. This assumption reflects the possibility that the spent fuel storage canisters and the fuel rod cladding will be corroded by the salt during the period the repository is open (roughly 6 to 20 years, and volatile materials in the fuel will escape to the environment. The staff assumed, however, that after the repository is sealed there would be no further release of radioactive materials to the environment.[87]

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[86] The release of carbon-14 as carbon-14 dioxide gas is covered separately below.
[87] NRC 1979.

The NRC made this assumption in the context of disposal in a bedded salt repository, which, as noted, is obsolete for spent fuel. It is also not conservative for any other geologic setting, since iodine-129 releases into groundwater could cause much higher doses either via groundwater or where the groundwater is discharged into surface water.

For instance, the largest dose calculated by the French nuclear waste agency ANDRA, was due to I-129 in spent fuel. As noted in Section A, the whole body effective dose equivalent from I-129 in the event of seal failure was estimated to be 1,500 millirem, greatly in excess of both the French and current U.S. EPA performance requirements. Since the main organ that is irradiated is the thyroid, the implied dose to the thyroid is about 30,000 millirem.[88]

It is clear that under present circumstances, with present technical information, and under current law, Table S-3 is not conservative. On the contrary, by assuming that I-129 is dispersed into the atmosphere, the doses are implicitly assumed to be quite low. For instance, WASH-1248, the document underlying 10 CFR 51, estimates the thyroid dose due to the release of volatile radionuclides (mainly I-129) as only 6.3 millirem from one-reactor year of operation.

This dose appears to be well with compliance limits and hence the NRC can proceed to license reactors on this basis. However, if it is assumed that spent fuel will be disposed of in a geologic repository where groundwater could become contaminated, then the performance measure to be used is not longer that applying to one reactor for one year, but whether the geologic repository system is suitable for disposal of all the spent fuel that is created in the program as a whole. In the French case, the spent fuel disposed of is much less than will be required in the U.S., since the French have fewer reactors and they have reprocessing. It is plausible that the U.S. impacts from iodine disposal could therefore be far in excess of the limits set in 40 CFR 197 for geologic disposal.[89] Therefore the cumulative impact of licensing new reactors and re-licensing existing reactors would be far in excess of that estimated in Table S-3, which assumes zero releases into the environment from disposal of solid spent fuel.

Other parts of Table S-3 relating to volatile or gaseous radionuclides are also obsolete. For instance, Table S-3 assumes a release of 400,000 curies of krypton-85 into the atmosphere per reactor-year. While this may be conservative, it is greatly in excess of the EPA's maximum allowable release of krypton-85 from one-gigawatt-year[90] of operation as specified in 10 CFR 190.10(b):

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[88] Calculated using thyroid and committed dose equivalent dose conversion factors for ingestion of iodine-129 in EPA 1999 and 2002 suppl. The weighting factor used for the thyroid is 0.03, according to 40 CFR 191.
[89] The DOE's license application for Yucca Mountain estimates low doses only because it assumes near-total container integrity for very long periods of time and treats deliquescence-induced corrosion as insignificant.
[90] This is equal to one 1,000 megawatt reactor operating for one year at 100 percent capacity factor. Table S-3 assumes a "Reference Reactor Year" which is the same reactor operating at 80 percent capacity factor,

> (b) The total quantity of radioactive materials entering the general environment from the entire uranium fuel cycle, per gigawatt-year of electrical energy produced by the fuel cycle, contains less than 50,000 curies of krypton-85, 5 millicuries of iodine-129, and 0.5 millicuries combined of plutonium-239 and other alpha-emitting transuranic radionuclides with half-lives greater than one year.[91]

Hence, the assumed release of Kr-85 in Table S-3 is far in excess of that allowed under current EPA rules, demonstrating yet another aspect of the obsolescence of Table S-3. We understand that these releases would occur mainly in the case of the reprocessing option being chosen and that reprocessing is not the current law for spent fuel management and disposal. But Table S-3 is designed to cover both the reprocessing and non-reprocessing cases. The releases it estimates, as an upper bound, are not in compliance with current regulations.

Table S-3's estimate of 1,300 millicuries (1.3 curies) of iodine -129, and 203 millicuries (0.203 curies) of fission products and transuranic radionuclides not otherwise specified are also not aligned with 40 CFR 190.10(b).

It is clear that some of the NRC assesses releases from reactor operations to be insignificant that are far in excess of those allowed by the EPA. The fact that these releases would be primarily from reprocessing operations and that reprocessing is no longer envisaged as the basis for disposal only highlights the obsolescence of Table S-3.

Further, it is possible that reprocessing may become the basis for spent fuel management for some or all of spent fuel. While we have concluded that such a course would create far more serious problems than it solves, it is nonetheless within the realm of possibility. For instance, it is part of a set of options being considered under the Global Nuclear Energy Partnership.[92]

As of April 2008, U.S. nuclear power plants had created 56,000 metric tons of spent fuel. The DOE anticipates that 119,000 metric tons of spent fuel will be created by existing reactors by 2035. There is some uncertainty about waste generation per reactor for new reactors, since it will depend on enrichment, burn-up etc. But 30 new reactors would likely generate in excess of 600 metric tons per year of spent fuel, or 24,000 metric tons over 40 years.

In sum, just considering spent fuel alone, there are a many ways in which Table S-3 is obsolete and/or incorrect. Hence revision of operational norms and release estimates in both the reprocessing and non-reprocessing cases is essential as is a reevaluation of the impacts and costs in a new generic EIS.

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see NUREG-0116, Table 3.2, p. 3-14. When translated into the same basis as the EPA regulation, the krypton-85 emissions would be 500,000 curies per gigawatt-year.

[91] 40 CFR 190.10(b) 2008

[92] GNEP PEIS draft 2008, see Section S.2.4 for a summary of options the DOE is considering. A Final EIS has not yet been prepared.

4. Greater than Class C (GTCC) waste and low-level waste

Table S-3 is severely outdated with respect to GTCC waste. It is also outdated with respect to Class A, B, and C low-level waste.

a. GTCC waste

There was no GTCC waste category when the 10 CFR § 51.51 and Table S-3 was revised in the late 1970's.[93] NRC regulations regarding GTCC waste were part of low-level waste regulations, which were not issued until 1982 and revised periodically after that.[94] The Part 61 low-level waste regulations generally require disposal of GTCC in a deep geologic repository and prohibit shallow land burial unless a specific exemption is obtained.[95] At present Table S-3 assumes all solid radioactive waste, except high-level waste, including what is now called GTCC waste, will be buried in a shallow land burial facility.[96] This is clearly incorrect. GTCC waste cannot be disposed of in shallow low-level waste facilities unless a specific exemption to do so is provided by the NRC. None has been provided; nor is there any application for such an exemption.

GTCC waste has a relatively high radioactivity per unit volume and many components of GTCC waste have long half-lives. The impacts in the absence of repository disposal could therefore be considerable – though the amounts would be site specific. Therefore, Table S-3, which was prepared prior to the understanding that led to the creation of a GTCC category, cannot be relied upon for estimating the environmental impact of GTCC disposal. We note here that Table S-3 has been republished in the same way since the late 1970s without change, including after the low-level waste regulations requiring deep geologic disposal of GTCC waste (unless specifically exempted). The current version of 10 CFR 51 also contains this same provision for disposal "on site."[97] The following is copied from the present Table S-3 at 10 CFR 51.51[98]:

Solids (buried on site):		
Other than high level (shallow)	11,300	9,100 Ci comes from low level reactor wastes and 1,500 Ci] comes from reactor decontamination and decommissioning--buried at land burial facilities. 600 Ci comes from mills--included in tailing returned to ground. Approximately 60 Ci comes from conversion and spent fuel storage. No significant effluent to the environment.

Table S-3 is therefore legally wrong in its *a priori* assumption of shallow land burial (on site or at any site) of GTCC waste.

[93] NRC 1979. Table S-3 was first published in WASH-1248 and revised in the late 1970s, in which form it has been republished since that time.
[94] 10 CFR Part 61 2008
[95] See 10CFR 61.55(a)(2)(iv) 2008 and 10 CFR 61.55(a)(4)(iv) 2008.
[96] 10 CFR 51.51 2008. Table S-3 mentions onsite burial (i.e., "buried on site"). This would clearly not be allowed for any of the wastes discussed here.
[97] Disposal on site at reactors would not be permitted since none have a license do to so and no applications have been made. There are other issues as well in relation to low-level waste compacts see below.
[98] 10 CFR 51.51 2008.

The Department of Energy (DOE) is preparing an Environmental Impact Statement (EIS) regarding GTCC disposal.[99] This EIS is being prepared because the DOE considers the development of capability to dispose of GTCC waste as a "major Federal action."[100] A full evaluation of the impacts of options of GTCC disposal has never been done. The impacts of GTCC disposal as evaluated in this EIS need to be incorporated into a revised Table S-3. .

Table S-3 is also incorrect in another respect. As can be seen, above, it assumes that there will be "[n]o significant effluent to the environment" and no health impact is estimated. In other words, the assumption here is the same as that for high-level waste and spent fuel disposal – zero environmental impact.

The more stringent requirement for GTCC waste disposal is because the specific activity of the waste is higher than for the Class A, B, and C low-level waste categories as defined in 10 CFR 61.55. No difference in the types of radionuclides or their chemical composition is assumed to exist. The technical inference clearly is that shallow land burial would produce greater impacts than Class A, B, and C waste disposal. The radiation doses estimated by the NRC for these latter waste categories in its low-level waste EIS are greater than zero for all disposal cases, even those in conformity with the 10 CFR 61 regulations, over a period of 500 years.[101] *A forteriori*, the impacts associated with GTCC disposal in shallow land burial at the same reactor site or at some other site would likely be greater.

While the impacts of Disposal of GTCC waste disposal have not been evaluated in the United States, they are required to be disposed of in a deep repository in France. The French evaluation of Class B waste (corresponding approximately to GTCC waste) provides some interesting evidence. According to ANDRA's assessment, the dose from Class B waste disposal at the French Bure site could exceed allowable limits due to exposure to chlorine-36 in the scenario that assumes a failure of the repository seals.[102]

There is no explicit discussion of transuranic waste in Table S-3. Yet NUREG-0116, which supplements WASH-1248, and which is referred to in the notes to Table S-3 explicitly mentions that transuranic waste, mainly generated during reprocessing, should be disposed of in a deep geologic repository. Table S-3 does not even consider chlorine 36.

There will be a considerable amount of GTCC waste even if there is no reprocessing. The DOE estimated that a Boiling Water Reactor would generate 47 cubic meters and a

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[99] See DOE 2007 and DOE 2007b.

[100] According to the GTCC EIS website set up by Argonne National Laboratory for the GTCC EIS process, "The Secretary of Energy has determined that development of disposal capability for GTCC LLW is a major Federal action that may have a significant impact upon the environment within the meaning of the National Environmental Policy Act of 1969 (NEPA)." On the Web at http://www.gtcceis.anl.gov/eis/why/index.cfm.

[101] NRC 1982, v. 1, Table 4.6 (pp. 4-30 to 4-32).

[102] ANDRA 2001, p. 139.

Pressurized Water Reactor would generate 133 cubic meters upon decommissioning.[103] On this basis the existing reactor fleet would generate in excess of 10,000 cubic meters of GTCC waste upon decommissioning.

Again, it clear that Table S-3 is obsolete or incorrect in a number of respects in regard to GTCC waste. The impact of this needs to be assessed either by the NRC as part of the impacts associated with nuclear energy production.

b. Class A, B, and C low-level waste

10 CFR 61 allows disposal of Class A, B, and C low-level waste in shallow land disposal facilities. However, such facilities must be licensed and must meet the dose limits specified at 10 CFR 61 Subpart C. Table S-3 mentions "on site" disposal. WASH-1248, the underlying document supporting Table S-3 also mentions on site disposal. No current reactor sites have such licenses. No application for a new reactor contains provision for obtaining a license for on-site disposal of low-level waste. The table needs to revised and clarified in this regard.

Table S-3 also assumes that shallow land disposal of waste will have not environmental and health impact. This is incorrect. The low-level waste EIS recognizes that some impacts may occur. The standard computational model used for assessing the radiation dose impact of land contamination (and disposal of radioactive waste in shallow land burial facilities is a form of land contamination) generally produces non-zero radiation doses under any reasonable assumption of technical site parameters. This is especially so as 10 CFR 61 Subpart C contains no time limit for performance. That is, the dose limits specified there must be met for the durations that are multiples of the longest lived radionuclides disposed of at the facility. Hence Table S-3 is obsolete and wrong in its assumption of essentially zero release from shallow land burial of low-level waste as well. .

5. Depleted Uranium

Table S-3 makes no mention of the large amounts of depleted uranium that will be generated in the course of enrichment of uranium to produce fuel for the proposed nuclear reactors. Large amounts of DU from uranium enrichment plants were not regarded as a waste when Table S-3 was created. But the Nuclear Regulatory Commission has declared depleted uranium as a low-level waste. However, the classification of large amounts of DU from enrichment plants within the low-level waste scheme (Class A, B, C or GTCC) has yet to be decided. The NRC as asked its staff to conduct a generic proceeding to determine such a classification.[104]

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[103] DOE data as cited in Makhijani and Saleska 1992, Table 6.
[104] "…the Commission directs the NRC staff, outside of this adjudication, to consider whether the quantities of depleted uranium at issue in the waste stream from uranium enrichment facilities warrant amending section 61.55(a)(6) or the section 61.55(a) waste classification tables." (NRC 2005).

The NRC staff has recently begun that assessment. It has determined that 10 CFR 61 does not automatically apply to DU in large amounts such as those created by enrichment plants. In fact, it has decided that DU from enrichment plants differs essentially from other low-level wastes in some respects in that it has a much higher level of specific activity, the radionuclides are exceptionally long-lived, and there is in-growth of thorium-230 and radium-226 (which emits radon-222) over hundreds of thousands of years.[105]

DU has radiological characteristics similar to Greater than Class C low-level waste, containing long-lived, alpha-emitting transuranic radionuclides at concentrations greater than 100 nanocuries per gram. Shallow land disposal of over 10,000 metric tons of DU would cause substantial health and environmental impacts in the long run. An assessment done by the Institute for Energy and Environmental Research in the context of evaluating the disposal of 133,000 metric tons of DU from an enrichment plant proposed for New Mexico, concluded that peak doses from the disposal would be in the hundreds of rem per year to the maximally exposed individual under a variety of shallow land disposal conditions, including disposal in dry or wet areas.[106] In contrast, the maximum allowable dose from low-level radioactive waste disposal is only 0.025 rem per year.[107] This means that DU from enrichment plants, over the life of the plant, if disposed of in shallow land burial, would produce doses thousands of times greater than the allowable limit at the time of peak dose.

The NRC staff paper has itself estimated that the disposal of DU in shallow land burial will cause non-zero radiation doses.[108]

Table S-3 does not take any of these realities into account. Indeed, at the time it was published in its present form, in the late 1970s, DU was not even considered a waste. However, the NRC now requires it to be considered as waste in the context of the licensing of uranium enrichment plants.[109] Hence Table S-3 is obsolete in not explicitly considering the impacts of DU.

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[105] Borchardt 2008 Enclosure 1.
[106] Makhijani and Smith 2004, Table 5 (p. 24). "Version for Public Release Redacted March 20, 2007."
[107] 10 CFR 61.41 2008
[108] Borchardt 2008, See Enclosure 1. Note that we do not agree with the results of the NRC staff's calculations. For instance, the NRC staff has assumed that "there will not be significant releases of waste to the environment from fluvial or aeolian erosion." This is completely unrealistic and in general scientifically incorrect for the time periods evaluated – well over 1,000 years and up to one million years. As a result, the quantitative impacts assessed by the NRC for arid sites are serious underestimates (since erosion is the main pathway for long-term dose, which is external dose, in arid areas). See Makhijani and Smith 2004. The NRC's conclusion that that some shallow land burial sites may be suitable for DU disposal is based on the incorrect assumption of zero erosion rates, is therefore also incorrect. There has been no scientifically credible demonstration that there would be essentially zero impact from erosion at shallow burial sites, even if these are more than three meters deep, given the time scales involved.
[109] NRC 2005

The 56,000 metric tons of spent fuel that have been created so far correspond to more than 300,000 metric tons of DU.[110] There will be hundreds of thousands of metric tons of additional DU due to future fuel production for the existing reactor fleet. Relicensing the rest of existing reactors and licensing new reactors will commit to production of further large amounts.[111]

DU cannot be buried at the reactor site or the enrichment plant site without an appropriate license. Under the current path, DU from an enrichment plant or even more than one enrichment plant may be disposed of at a single facility.

The impacts of DU management and disposal and whether such safe disposal of DU – that is disposal of DU in conformity with low-level waste disposal standards at 10 CFR 61 Subpart C – is possible needs evaluated in the generic EIS on waste that would include a revision of Table S-3. The costs of disposal that would conform to 10 CRF 61 Subpart C also need to be estimated.[112]

6. Radon

The matter of doses from radon-222 due to emissions from mill tailings had not been included in Table S-3. On March 20, 2008, the NRC denied a petition by the New England Coalition on Nuclear Pollution, which had requested that a value for the impact of radon-222 be included in Table S-3. In denying the petition, the NRC concluded that "the radiological impacts of the uranium fuel cycle, including those from radon-222 emissions, on individuals off-site will remain at or below the Commission's regulatory limits, and as such, are of small significance."[113] The NRC referred to Chapter 6 of NUREG-1437 for technical details about the denial.

Limiting radon-222 emissions from uranium mill sites requires the maintenance of the mill tailings site. This includes maintenance of a cover to prevent radon emissions:

> The design and implementation of the radon cover and erosion protection features are the primary reliance for maintaining radon emissions within the [10 CFR] Part 40 limits; significant failure of the covers is considered highly unlikely. However, the indefinite licensed long-term custody and care provide additional assurances.[114]

[110] This is an approximate figure. It is much greater than the amount used in the illustrative calculation in the paragraph before. The exact figure attributable to commercial nuclear power plants is difficult to estimate, since the U.S. has had dual use enrichment plants for its civilian and military enrichment requirements and because in recent years the U.S. has also imported enrichment services from Russia in the form of Russian highly enriched uranium that was downblended into low enriched reactor fuel.
[111] The exact amounts are difficult to estimate since some depleted uranium tails may be used as enrichment feedstocks and the assay of U-235 in the tails may vary as uranium prices change.
[112] See for instance Makhijani and Smith 2004.
[113] NRC 2008c. The quote is on p. 14947
[114] NRC 1996, Vol. 1, pp. 6-9 and 6-10.

This assumption that there will be custody and maintenance for the indefinite future in NUREG-1437 is patently absurd. While the decay of radium-226, which has a half-life of 1,600 years, is the proximate source of radon-222 emissions from mill tailings, radium-226 itself is the decay product of thorium-230.

So long as there is thorium-230 in the tailings, the amount of radium-226 will be about the same (excepting that part accounted for by differential environmental mobilization). Thorium-230 has a half-life of over 75,000 years. Hence, there will be significant amounts of radium-226 in the tailings ponds for about ten half-lives or about three quarter of a million years. No human institution has lasted even one percent of this time. The United States, which has had a long political continuity, is not even 300 years old, and it has had a Civil War less than a hundred years after its creation. While the Atomic Energy Act may require institutional control and maintenance of mill tailings, an environmental impact assessment is a technical matter. That assessment cannot rely on a legal requirement that is patently out of touch with any reasonable expectation or technical judgment. For instance, the National Research Council has advised that long-term institutional control should not be assumed in waste disposal or matters relating to the use of contaminated sites:

> *The committee believes that the working assumption of DOE planners must be that many contamination isolation barriers and stewardship measures at sites where wastes are left in place will eventually fail, and that much of our current knowledge of the long-term behavior of wastes in environmental media may eventually be proven wrong. Planning and implementation at these sites must proceed in ways that are cognizant of this potential fallibility and uncertainty.*[115]

The NRC has done exactly the opposite of the recommendation of the National Research Council. Instead of being "cognizant of this potential fallibility and uncertainty" arising from the failure of stewardship and the possibility of incorrect assumptions, it has simply reckoned that all of its essential assumptions and all the necessary institutions and finances will be in place for three quarters of a million years. While this time frame is not specified in NUREG-1437, it is implicit in it because radon-222 emissions ultimately originate in the thorium-230 present in the mill tailings. Indeed, over the long periods considered, the potential for high population doses due to erosion and airborne radioactive particles from the mill tailings should be explicitly considered.

Further, radon releases will also occur from DU disposal, which was not considered in Table S-3. DU disposal is now acknowledged by the NRC to create risks for a million years or more.[116] Since U-238 decay will create radium-226 buildup over time, radon-222 risks from DU disposal will persist for the indefinite future.

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[115] NAS-NRC 2000, p. 5. Italics in the original.

[116] Borchardt 2008. See for instance Figure 7. While this Figure stops at one million years, it is evident from the charts that non-zero doses continue after that time.

Finally, it should also be noted that EPA's Federal Guidance Report 13, which provides dose conversion and risk factors for persons by age does not provide any data for radon-222. In updating Table S-3 the NRC will need to consider whether children or women get a higher dose than men under specified environmental conditions.

7. Carbon-14

While Table S-3 makes an estimate of 24 curies of carbon-14 releases as gaseous effluents from one reactor year of operation, WASH-1248 does not provide an analysis of the dosimetric consequences. Carbon-14 is oxidized either during reprocessing or in an unsaturated oxidizing environment like Yucca Mountain. While the individual doses from C-14 releases can be expected to be very small, the population doses integrated over time would be very large. This is because carbon-14 has a very long half-life (5,730 years); it will continually be recycled through the biosphere along with non-radioactive carbon. Over ten thousand years, the population doses could be very high in an oxidizing environment. The SAB report cites a population dose of 14 million person rem over 10,000 years assuming that half the carbon-14 is released. This corresponds to 4,000 cancer fatalities over 10,000 years.[117] The total amount of spent fuel considered in this calculation was 70,000 metric tons of heavy metal, the present legal limit for repository disposal. The corresponding estimate per reactor-year, assuming 20 metric tons per reactor-year, would be 1.14 cancer fatalities over 10,000 years. This amounts to 45 fatal cancers due to carbon-14 releases from spent fuel generated over a 40-year operating life and twice that if the license is extended by another 40 years.

Such consequences would be estimated only for unsaturated oxidizing repositories, which is the description that fits the Yucca Mountain site as presently designed and characterized. They would also be estimated in reprocessing scenarios. Hence, the estimates of C-14 fatalities and corresponding estimates of cancer incidence need to be included in a revised Table S-3. We note here that the dose conversion factors have been updated since the EPA carbon-14 report, cited above, was published. Doses and cancer risks need to be calculated on an age-specific, gender-specific basis in the generic waste EIS.

8. Conclusions regarding aspects of Table S-3 other than Spent Fuel and High-Level Waste

Table S-3 is obsolete and/or wrong in its legal, technical, environmental and health assumptions and estimates in regard to spent fuel, gaseous releases from spent fuel, GTCC waste, Class A, B, and C low-level waste, DU, radon-222, and carbon-14. In light or more rigorous requirements for waste management and the fact that repository costs have escalated without a repository having been commissioned as previously envisaged, a thorough revision of the cost basis of nuclear power in regard to its waste aspects is also

[117] Loehr, Nygaard, and Watson 1993, p. 21

needed. This is essential because without such estimates, the costs of nuclear energy with alternative options cannot be fairly made.

A generic environmental impact statement must compare the environmental impacts and costs of the present course with the following alternatives in regard to spent fuel:

1. At reactor storage for the indefinite future, including periodic replacement of storage containers and inter-container transfer.
2. Consolidated monitored storage in one or more locations for the indefinite future, including replacement and transfer as in Item 1 above.
3. Yucca Mountain at 70,000 metric tons with no second repository.
4. Yucca Mountain at a higher capacity than 70,000 metric tons.
5. Yucca Mountain with a second repository.
6. Yucca Mountain fails as a program and one or more other sites in a new program to accommodate all spent fuel.
7. Reprocessing of spent fuel with fast reactor reuse of plutonium and uranium, plus a waste repository for high-level waste and Greater Than Class C waste.
8. Reprocessing with light water reactor re-use of plutonium (including costs of reactor modification), with a repository as in Item 7 above.
9. Reprocessing of spent fuel without fast reactor reuse of plutonium and uranium, with a repository as in Item 7 above.
10. Uranium only fuel recycle, with a repository as in Item 7 above.
11. Partial reprocessing, with repository disposal of uranium and mixed uranium-plutonium oxide spent fuel, uranium spent fuel, high-level waste and Greater Than Class C waste.

The risk of terrorist attacks and proliferation risks must be included in the generic EIS. These risks are different for the various options and those differentials need to be factored into the process of choosing a preferred alternative in the EIS process.

It must also consider the various options for GTCC disposal and DU disposal that would conform with existing low level waste dose limits specified at 10 CFR 61 Subpart C.

A waste confidence rule as well as a generic EIS on spent fuel must consider the above alternatives and provide cost estimates for them. These costs must be added to reactor costs for new reactors in the licensing process and in the re-licensing process of existing reactors. The costs must be added to nuclear power costs when evaluating alternatives when preparing environmental impact statements for new reactors. Without a realistic estimate of costs and a generic waste confidence EIS, the EIS process for new reactor licenses and the adjudicatory process for re-licensing reactors will remain fundamentally deficient. If the costs of repository alternatives cannot be realistically estimated based on present U.S. data and history (including technical, legal, regulatory, political, social, and fiscal aspects), then the waste confidence finding must be that there is no reasonable assurance that a repository for spent fuel can be opened in the United States at any time in the foreseeable future. Specifically, if a well-founded upper bound cannot be attributed to waste management and disposal costs, then there is no basis on which to

compare the total costs of nuclear with various combinations of renewable energy, storage, and combined heat and power, and efficiency alternatives as a part of the EIS process of licensing new reactors.

D. Conclusions

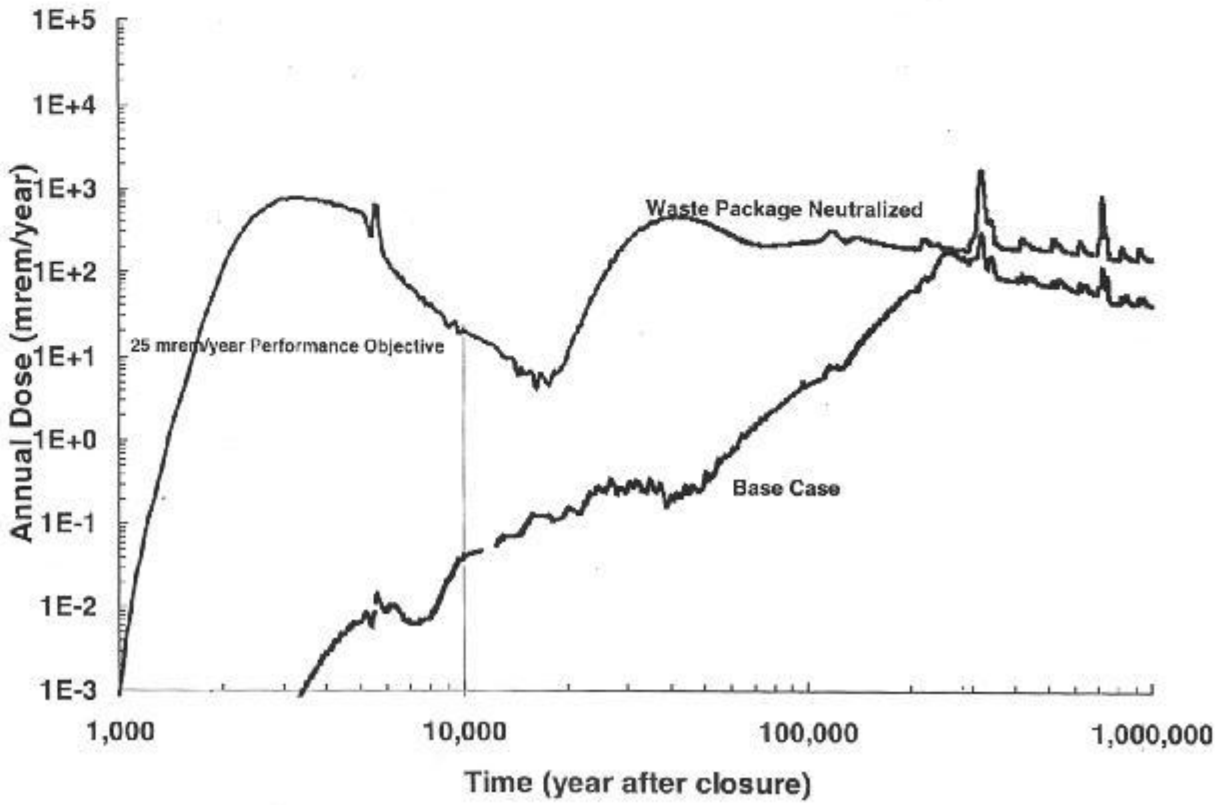
The NRC has not provided a sound scientific, technical, legal, political, social financial, or fiscal basis for its conclusions that (i) a geologic repository for disposal of spent fuel is technically feasible, (ii) it can state with reasonable assurance that a geologic repository to accommodate the required waste volumes can be opened within 50 to 60 years after the license expiry of any U.S. nuclear power plant, including new plants.

Further, Tables S-3 is either obsolete or wrong needs to be fundamentally revised to take into account new scientific and legal realities. We have concluded that at present there is no reasonable assurance that a repository in the United States can be opened within the time frame specified in the revised Finding 2 or indeed at any time. A generic EIS on nuclear spent fuel management, including a revision of Tables S-3, is required before new reactors can be licensed or existing reactors can be relicensed.

This generic EIS should include consideration of the impacts of the various options described above. It should include consideration of costs of the various options. Compliance with regulations limiting public exposure should be the fundamental basis for assessing whether the impact is small or not. Note that compliance with annual dose limits needs to be estimated for the most exposed individual, who may be a male or female, infant, or a male or female of any other age, using dose conversion factors that are specific to that age and gender. Population doses should also be estimated as this is important for understanding the full extent of the health risks over time. Other aspects of waste management and disposal to be considered as part of the process of licensing new reactors or relicensing existing reactors are discussed above.

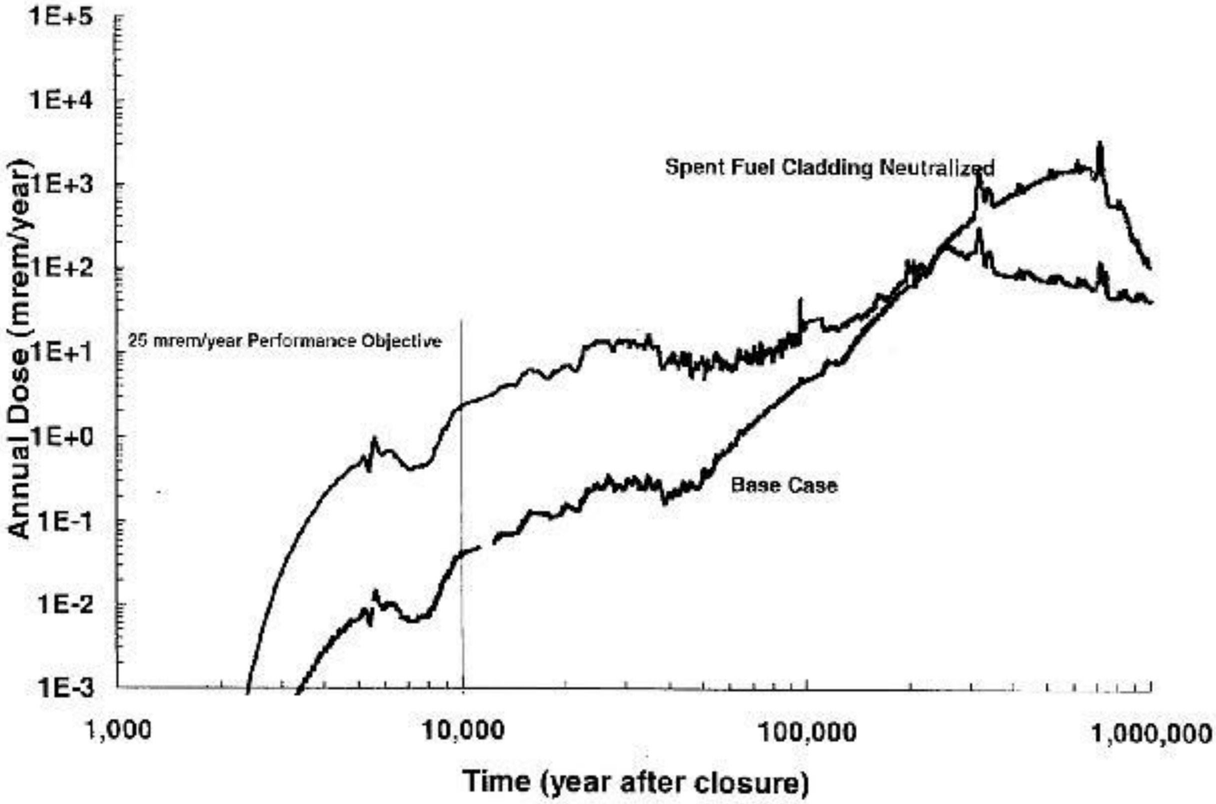
Attachment A[118]

Graph A: Neutralize Waste Package

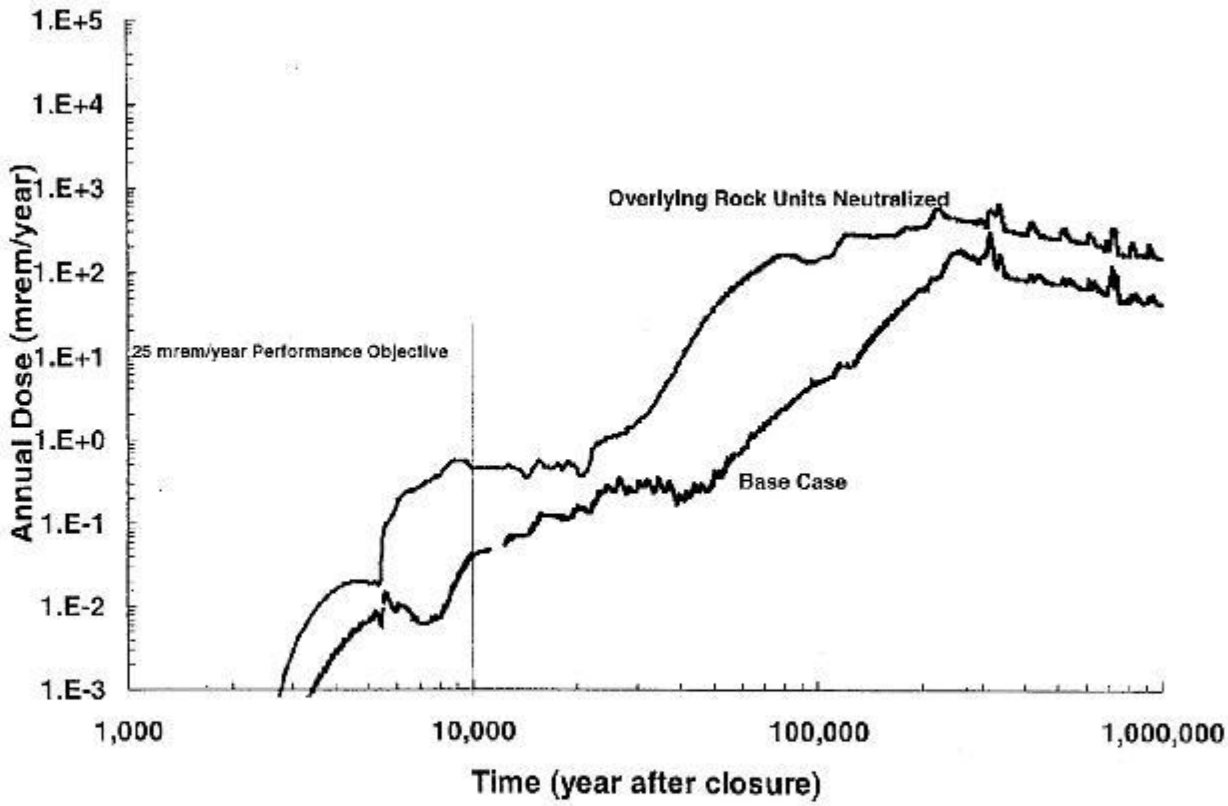


118 Source for all graphs: DOE OCRWM 1999.

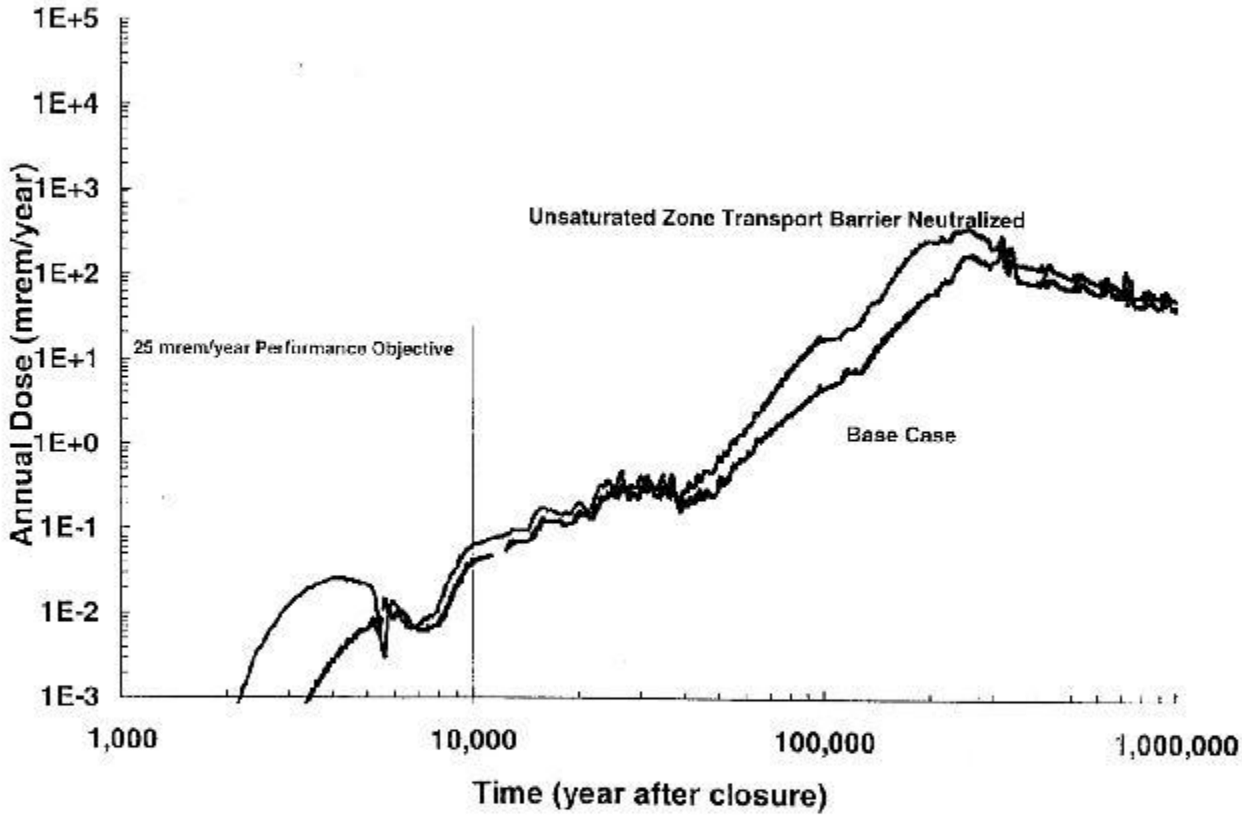
Graph B: Neutralize Spent Fuel Cladding



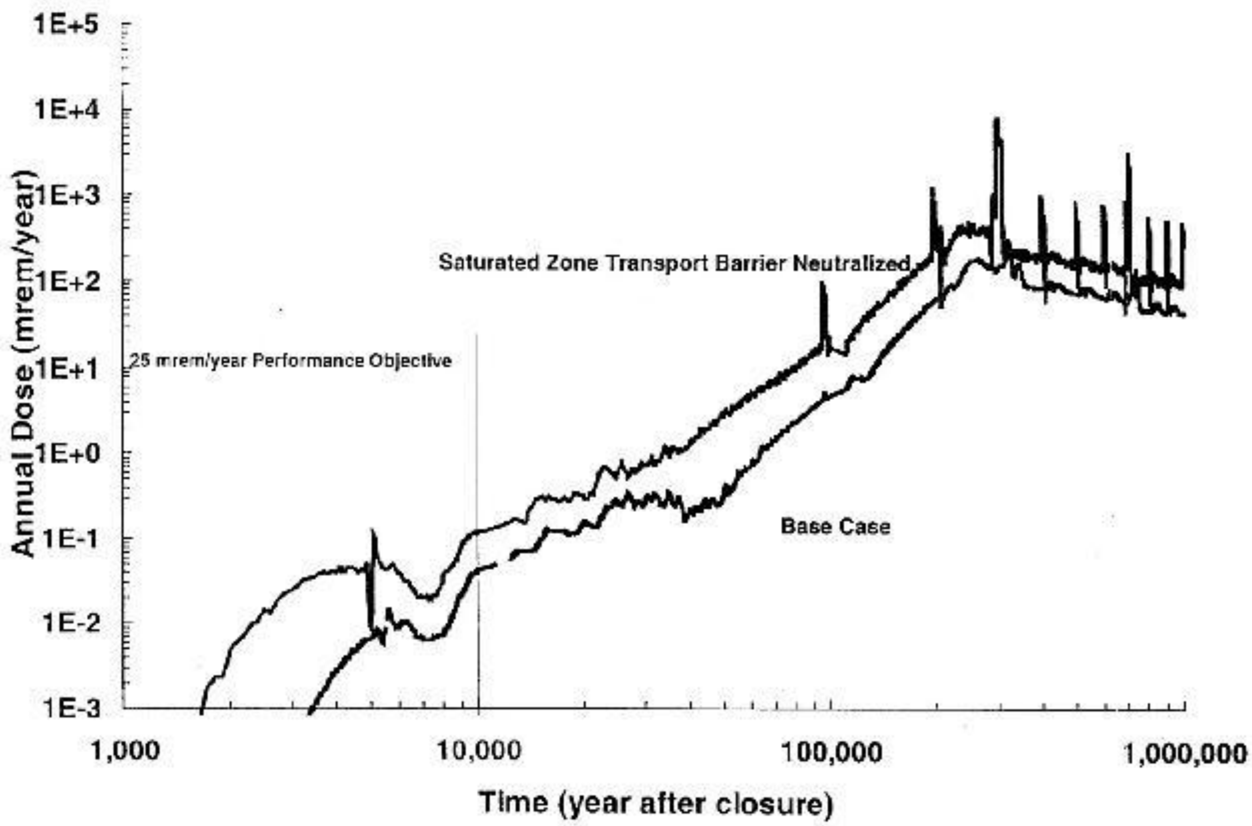
Graph C: Neutralize Overlying Flow Barriers



Graph D: Neutralize Unsaturated Zone Transport Barrier



Graph E: Neutralize Saturated Zone Transport Barrier



Source for all graphs: U.S. DOE Office of Civilian Radioactive Waste Management, "NWTRB Repository Panel meeting: Postclosure Defense in Depth in the Design Selection Process," presentation for the Nuclear Waste Technical Review Board Panel for the Repository, January 25, 1999. Presented by Dennis C. Richardson. Online at http://www.nwtrb.gov/meetings/1999/jan/richardson.pdf.

Attachment B

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Curriculum Vitae

des membres de l'équipe IEER et un relecteur

présent à l'IEER 29-30 novembre 2004

Examen critique du programme de recherche de l'ANDRA pour déterminer l'aptitude du site de Bure au confinement géologique des déchets à haute activité et à vie longue

RAPPORT FINAL

préparé par
l'Institut pour la recherche sur l'énergie et l'environnement (IEER)

pour
Le Comité Local d'Information et de Suivi

Directeur du Projet
Arjun Makhijani, Ph.D.

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27 décembre 2004
avec corrections 11 janvier 2005

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Les différents membres de l'équipe ont eu la responsabilité des disciplines scientifiques suivantes et ont rédigé les chapitres correspondants :

Chapitre 1: Principes de confinement géologique - Arjun Makhijani. Yuri Dublyansky a contribué à la section sur la paléoclimatologie
Chapitre 2: Mécanique des roches - Jaak Daemen
Chapitre 3: Aspects thermiques de la conception et de la construction du site de stockage - George Danko
Chapitre 4: Programme de recherches sur le terme source et le champ proche - Rod Ewing
Chapitre 5: Hydrogéologie - Detlef Appel
Chapitre 6:Aspect minéralogiques et géochimiques dans la formation hôte - Yuri Dublyansky
Chapitre 7: Sismologie et déformation - Gerhard Jentzsch et Horst Letz

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Ph.D. University of California, Berkeley, 1972, from the Department of Electrical Engineering. Area of specialization: plasma physics as applied to controlled nuclear fusion. Dissertation topic: multiple mirror confinement of plasmas.

M.S. (Electrical Engineering) Washington State University, Pullman, Washington, 1967. Thesis topic: electromagnetic wave propagation in the ionosphere.

Bachelor of Engineering (Electrical), University of Bombay, Bombay, India, 1965.

Current Employment:

1987-present: President and Senior Engineer, Institute for Energy and Environmental Research, Takoma Park, Maryland. (part-time in 1987).

February 3, 2004-present, Associate, SC&A, Inc., one of the principal investigators in the audit of the reconstruction of worker radiation doses under the Energy Employees Occupational Illness Compensation Program Act under contract to the Centers for Disease Control and Prevention, U.S. Department of Health and Human Services.

Professional Societies:

Institute of Electrical and Electronics Engineers and its Power Engineering Society
American Physical Society
Health Physics Society
American Association for the Advancement of Science

Official positions

Subcommittee on carbon-14 emissions from Yucca Mountain of the Radiation Advisory Committee, U.S. Environmental Protection Agency, 1992-1993

Radiation Advisory Committee, U.S. Environmental Protection Agency, 1992-1994

Technical Advisory Panel, Hanford high level waste tanks, early 1990s (ex-officio)

Consultant to the Office of Technology Assessment of the U.S. Congress

Consulting Experience, 1975-1987

Consultant on a wide variety of issues to various organizations including:

Tennessee Valley Authority
Lower Colorado River Authority
Federation of Rocky Mountain States
Environmental Policy Institute
Lawrence Berkeley Laboratory
Food and Agriculture Organization of the United Nations
International Labour Office of the United Nations
United Nations Environment Programme

United Nations Center on Transnational Corporations
The Ford Foundation
Economic and Social Commission for Asia and the Pacific
United Nations Development Programme

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Fioravanti, M. and A. Makhijani, *Containing the Cold War Mess: Restructuring the Environmental Management of the U.S. Nuclear Weapons Complex,* Institute for Energy and Environmental Research, Takoma Park, October 1997.

Makhijani, A., Bernd Franke, and Hisham Zerriffi, *Preliminary Partial Dose Estimates from the Processing of Nuclear Materials at Three Plants during the 1940s and 1950s*, Institute for Energy and Environmental Research, Takoma Park, September 2000. (Prepared under contract to the newspaper *USA Today*.)

Makhijani, A. and Bernd Franke, *Final Report of the Institute for Energy and Environmental Research on the Second Clean Air Act Audit of Los Alamos National Laboratory by the Independent Technical Audit Team*, Institute for Energy and Environmental Research, Takoma Park, December 13, 2000.

Makhijani, Arjun, Hisham Zerriffi, and Annie Makhijani, "Magical Thinking: Another Go at Transmutation," *Bulletin of the Atomic Scientists,* March/April 2001.

Makhijani, A. and Michele Boyd, *Poison in the Vadose Zone: An examination of the threats to the Snake River Plain aquifer from the Idaho National Engineering and*

Environmental Laboratory Institute for Energy and Environmental Research, Takoma Park, October 2001.

Makhijani, A. and Sriram Gopal, *Setting Cleanup Standards to Protect Future Generations: The Scientific Basis of Subsistence Farmer Scenario and Its Application to the Estimation of Radionuclide Soil Action Levels (RSALs) for Rocky Flats*, Institute for Energy and Environmental Research, Takoma Park, December 2001.

Makhijani, A. and Michele Boyd, *Nuclear Dumps by the Riverside: Threats to the Savannah River from Radioactive Contamination at the Savannah River Site*, Institute for Energy and Environmental Research, Takoma Park, Maryland, forthcoming, March 2004.

Annie Makhijani

Education:
M.S. (Chemistry, with emphasis on Physical Chemistry) University of Maryland, College Park, Maryland, 1994. Research topic: the physical properties of nanostructures.
Bachelor of Science (Chemistry) University of Maryland, College Park, 1985.
Studied Hindi at the Institut des Langues Orientales in Paris (1980).
Bachelor of Arts (Psychology) Université de Tours, France (1972)

Employment:
- 1994-present: Project Scientist, Institute for Energy and Environmental Research, Takoma Park, Maryland.
- Staff Scientist, Institute for Energy and Environmental Research, Takoma Park, Maryland.
- Consultant for the White House Council on Environmental Quality (1979).
- French teacher, Alliance Française, Bombay, India (1977-1979)

Publications:
- Makhijani, Arjun and Annie Makhijani, *Fissile Materials in a Glass Darkly:* Technical *and Policy Aspects of the Disposition of Plutonium and Highly Enriched Uranium*, IEER Press, Takoma Park, 1995.
- Hisham Zerriffi and Annie Makhijani, *An Assessment of Transmutation as a Nuclear Waste Management Strategy,* Institute for Energy and Environmental Research, Takoma Park, 2000.

Some accomplishments
- Did research on the management of depleted uranium for the proposed Claiborne uranium enrichment plant in Louisiana (1996).
- Did research on the decommissioning or the Sequoyah uranium conversion plant in Oklahoma.
- Was responsible for some of the background research for the Institute for Energy and Environmental Research technical report: *Radiation Exposures in the Vicinity of the Uranium Facility in Apollo, Pennsylvania* (1998).

RESUME
JAAK J.K. DAEMEN

Education: Ph.D. Geo_Engineering, University of Minnesota, June 1975
Mining Engineer (Honors), University of Leuven, Belgium, July 1967

Registration: State of Arizona: Registered P.E. Civil Engineering (AZ 12158) and Mining Engineering (AZ 12980)

Professional:
American Institute of Mining Engineers, American Society of Civil Engineers, International Society for Soil Mechanics and Foundation Engineering, American Society for Engineering Education, International Society for Rock Mechanics, Royal Flemish Engineering Association, Royal Belgian Society of Engineers and Industrialists, American Geophysical Union, American Rock Mechanics Association.

Past Member, National Tunneling Committee, U.S. National Rock Mechanics Committee and Committee on Geological and Geotechnical Engineering of the National Research Council of the National Academy of Sciences; Reviewer for National Science Foundation, Geotechnical Engineering Program; U.S. Geological Survey; Mining Engineering, Society of Mining Engineers of AIME; International Journal of Rock Mechanics and Mining Sciences; Water Resources Research; Canadian Geotechnical Journal

Employment Record:

October 2001 - Present Professor, Mining Engineering, Mackay School of Mines, University of Nevada, Reno.

July 1990 - Sept.2001 Professor and Chair, Mining Engineering, Mackay School of Mines, University of Nevada, Reno.

September 1976 _ June 1990 Assistant and Associate Professor, University of Arizona, Department of Mining and Geological Engineering.

Summer 1980, 1981 Visiting Associate Research Engineer, Research Associate, University of California, Berkeley.

Summer 1977 Occidental Research Corporation. Investigations of roof control problems, Island Creek Coal Company.

April 1975 - September 1976 Research Engineer, E. I du Pont de Nemours & Co., Potomac

River Development Laboratory, Martinsburg, West Virginia 2504.

Sept. 1967 - March 1975 Research Assistant, Teaching Assistant, Teaching Associate, Research Fellow and Post_Doctoral Research Associate, Univ. of Minn, Minneapolis, Department of Civil & Mineral Engineering.

Sponsored Research:
Mechanics of Fully Grouted Bolts in Bedded Mine Rook (United Engineering Foundation); Rock Mass Sealing (U.S. Nuclear Regulatory Commission); Numerical Analysis of the influence of Bench Stiffness on Rock Fragmentation in Surface Blasting (AZ MMRRI); Ground and Air Vibrations Induced by Large Surface Blasts (Office of Surface Mining; U.S. Bureau of Mines); Mechanical Characterization of Welded Tuff (Center of Nuclear Waste Regulatory Analyses); Permeability-Strain Measurements in Rock Salt (Sandia National Laboratories); Sealing Studies for WIPP (SNL); Sealing Studies for Yucca Mountain, (SNL), Rock
Movement Induced by Blasting (Placer Dome); Long Term Drift Sability (DOE).

Courses Taught:
University of Arizona: Rock Excavation Practice; Tunneling and Underground Construction; Surface Mining; Coal Mining; Geomechanics; Applied Geomechanics: Underground Construction; Advanced Geomechanics; Design of Underground Structures; Rock Fracture and Flow; Subsidence Engineering; Rock Dynamics: Drilling, Blasting; Key Block Theory; Boundary Element Analysis.
University of Nevada, Reno: MINE 210 Mining Methods; MINE 301 Coal Mining; MINE 380 Quarry Engineering; MINE 445 Rock Excavation; MINE 448 Rock Mechanics; MINE 658 Rock Mechanics for Underground Mining and Construction.

Consulting: Morrison_Knudsen, Inc.; Sandia National Laboratories; Anaconda Minerals Company; Golder Associates; E.I. du Pont de Nemours & Co.; Fluor Mining & Metals; Cia Minera Las Cuevas, San Luis Potosi; Engineers International, Inc.; Itasca Consulting Group, Inc.; Nuclear Waste Management Consultants, Inc.; GRC Consultants, Inc; Hargis and Associates, Inc.; Southwest Research Institute; Asarco Mining Co., Inc.; Getchell Gold , Inc.; Petroplug, Inc.; U.S. DOE, J.S. Redpath.

CURRICULUM VITAE OF DR. GEORGE DANKO

EDUCATION:

Ph.D.	(Candidacy Degree in Technical Sciences), 1985, Hungarian Academy of Sciences. Thesis: Measurement and Model-building for the Convective Heat Transfer Examinations.
Dr. Tech.	(Doctor's Degree in Fluid Dynamics), 1976, Department of Fluid Dynamics, University of Technology, Budapest. Thesis: Matrix Analysis of Hydraulic Transients in Pipeline Flow.
M.S.	Applied Math, 1975, Eotvos University of Sciences, Budapest
M.S.	Mechanical Engineering, 1968, University of Technology, Budapest

EMPLOYMENT HISTORY:

7/95-present	Professor, Mining Engineering Department, Mackay School of Mines, University of Nevada, Reno.
8/90-6/95	Associate Professor, Mining Engineering Department, Mackay School of Mines, University of Nevada, Reno.
09/87-8/90	Lecturer in Mechanical Engineering, College of Engineering, University of Nevada, Reno.
11/86-8/90	Research Associate, Mining Engineering Department, Mackay School of Mines, University of Nevada, Reno.
1/79-11/86	Associate Professor, Institute of Thermal Energy and Systems Engineering, University of Technology, Budapest.
8/78-1/79	Visiting Postdoctoral Associate, Department of Mechanical Engineering, University of Minnesota.
9/75-8/78	Fellow of Hungarian Academy of Sciences.
8/68-9/75	Assistant Professor, Department of Mechanical Engineering, University of Technology, Budapest.

Selected recent publications relevant to nuclear waste disposal:

Danko, G., (1999), "In Situ REKA Probe Measurements at Yucca Mountain," Proceedings, International Bureau of Mining Thermophysiscs, St. Petersburg, pp 1-12.

Danko, G., (2000), "Coupled Convection-Diffusion Modeling with MULTIFLUX," Proceedings of the International Symposium on Hydrogeology and the Environment, Wuhan, China, pp 26-31.

G. Danko, D. Bahrami, (2001), "Ventilation Analysis of a Cold Conceptual Repository using MULTIFLUX with NUFT," Proceedings, 9th International high-Level Radioactive Waste Management Conference , April 29th-May 3rd.

G. Danko, D. Bahrami, and A. Adu-Acheampong, (2001), "In Situ Thermophysical Properties Measurements Under Hydrothermal Disturbances at DST," Proceedings, 9th International high-Level Radioactive Waste Management Conference , April 29th-May 3rd.

G. Danko and D. Bahrami, (2002), “The Application of CFD to Ventilation Calculations at Yucca Mountain”, Proceedings, WM 02’ Conference, February 24-28, 2002, Tucson, AZ, Session 39B, Paper 12, Abs. 243, pp. 1-11.

Danko, G., Shah, N., and Bahrami, D., (2002). "Evaluation of Lithophysal Conductivity, Diffusivity, and Porosity Measurements using the REKA Method," Proceedings, WM’ 02 Conference, February 24-28, Tucson, AZ. pp. 1-13.

Danko, G., Jain, A., (2002). "Parameter Identification of a Numerical Transport Code," Proceedings, WM’ 02 Conference, February 24-28, Tucson, AZ. pp.1-7.

Danko, G., and Bahrami, D., (2003). " Sensitivity Analysis of Ventilation Parameters and Site Input Properties," Proceedings, 10th Int. High-Level Radioactive Waste Management Conference, pp.1-8.

Danko, G., and Bahrami, D., (2003). "Natural Ventilation of a Deep Geologic Nuclear Waste Storage Facility," Proceedings, 10th Int. High-Level Radioactive Waste Management Conference, pp.1-8.

Danko, G., Shah, N., and Bahrami, D., (2003). "Monte Carlo Analysis of In Situ Lithophysal Properties Identification," Proceedings, 10th Int. High-Level Radioactive Waste Management Conference, pp.1-10.

Danko, G., Shah, N., and Bahrami, D., (2003). "In Situ Thermophysical Properties Variation at DST, Yucca Mountain," Proceedings, 10th Int. High-Level Radioactive Waste Management Conference, pp.1-8.

Danko, G., Bahrami, D., Leister, P., and Croise, J., (2003). "Temperature and Humidity Control for Underground Spent Fuel Storage," Proceedings, 10th Int. High-Level Radioactive Waste Management Conference, pp.1-8.

RODNEY C. EWING

Rod Ewing is a professor in the Department of Nuclear Engineering and Radiological Sciences at the University of Michigan, responsible for the program in radiation effects and nuclear waste management. He also holds appointments in Geological Sciences and Materials Science & Engineering and is an Emeritus Regents' Professor at the University of New Mexico in the Department of Earth and Planetary Sciences, where he was a member of the faculty from 1974 to 1997 and chair of the department from 1979 to 1984. He is also an *Adjungeret Professor* at the University of Aarhus in Denmark.

Ewing received a B.S. degree in geology from Texas Christian University (1968, summa cum laude) and M.S. (l972) and Ph.D. (l974, with distinction) degrees in mineralogy from Stanford University where he held an NSF Fellowship. His graduate studies focused on an esoteric group of minerals, metamict Nb-Ta-Ti oxides that are unusual because they have become amorphous due to radiation damage caused by the presence of radioactive elements (U and Th) and radionuclides in their decay series. This radiation-induced phase transformation from a crystalline to amorphous (periodic-to-aperiodic) structure can have significant effects on the properties of materials, such as the decreased durability of radioactive waste forms. Over the past twenty years, the early study of these unusual minerals has blossomed into a broadly based research program on radiation effects in complex ceramic materials. Such studies have lead to the development of techniques to predict and confirm the very long-term behavior of materials, such as those used in radioactive waste disposal. The key to such studies has been the use of natural phases of great age in designing highly durable nuclear waste forms. Present research includes: radiation effects caused by heavy-particle interactions with crystalline materials (e.g., ion-beam modification of ceramics and minerals); the structure and crystal chemistry of complex Nb-Ta-Ti oxides; the crystal chemistry of actinide and fission product elements, the application of "natural analogues" to the evaluation of the long-term durability of radioactive waste forms and the release and transport of radionuclides; the low-temperature corrosion of silicate glasses; the neutronics and geochemistry of the natural nuclear reactors in Gabon, Africa. The research has utilized a wide variety of solid-state characterization techniques, such as x-ray diffraction, x-ray absorption spectroscopy and high-resolution electron microscopy. The work of the research group has been supported not only by U.S. funding agencies but also from sources abroad (Sweden, Germany, Australia and Japan, as well as by the European Union and NATO). Ewing is the author or co-author of approximately 400 research publications and the editor or co-editor of seven monographs, proceedings volumes or special issues of journals. He was recently granted a patent for the development of a highly durable material for the immobilization of excess weapons plutonium. He received a Guggenheim Fellowship in 2002.

Ewing is a fellow of the Geological Society of America and the Mineralogical Society of America and has served the Materials Research Society as a Councilor (1983-1985; 1987-1989) and Secretary (l985-l986). He was president of the Mineralogical Society of America (2002) International Union of Materials Research Societies (1997-1998) and the New Mexico Geological Society (1981). He was a member of the Board of Directors of the Caswell Silver Foundation (l980-l984) and Energy, Exploration,

Education, Inc. (l979-l984). He has served as a guest scientist or faculty member at Battelle Pacific Northwest Laboratories, Oak Ridge National Laboratory, the Hahn-Meitner-Institut in Berlin, the Department of Nuclear Engineering in the Technion University at Haifa, the Centre D'Etudes Nucléaires de Fontenay-Aux-Roses, Commissariat A L'Énergie Atomique in France, Charles University in Prague, the Japan Atomic Energy Research Institute, the Institut für Nukleare Entsorgungstechnik of the Kernforschungszentrum Karlsruhe, Aarhus University in Denmark, Mineralogical Institute of Tokyo University and the Khlopin Radium Institute in St. Petersburg, Russia.

The involvement in issues related to nuclear waste disposal has proceeded in parallel with the basic research program most notably in association with the activities of the Materials Research Society where he has been a member of the program committee and the editor or associate editor for the proceedings volumes for the symposia on the "Scientific Basis for Nuclear Waste Management" held in Berlin-82, Boston-84, Stockholm-85, Berlin-88, Strasbourg-91, Kyoto-1994, Boston-1998 and Sydney-2000. He is co-editor of and a contributing author of *Radioactive Waste Forms for the Future* (published by North-Holland Physics, Amsterdam, 1988). Professor Ewing has served on National Research Council committees for the National Academy of Sciences that have reviewed the Waste Isolation Pilot Plant in New Mexico (1984 to 1996), the Remediation of Buried and Tank Wastes at Hanford, Washington and INEEL, Idaho (1992 to 1995), and the INEEL High-Level Waste Alternative Treatments (1998-1999), as well as a subcommittee on WIPP for the Environmental Protection Agency's National Advisory Council on Environmental Policy and Technology (1992 to 1998). He has served as an invited expert to the Advisory Committee on Nuclear Waste of the Nuclear Regulatory Commission and a consultant to the Nuclear Waste Technology Review Board. He is presently a member of the Board of Radioactive Waste Management of the National Research Council.

Dr. Detlef Appel

Professional background
Born 1943

1965-1971
study of geology at the University of Hannover, Lower Saxony, Germany, and the University of Vienna, Austria - diploma thesis on tectonical aspects of the Asse salt-structure in Lower Saxony (test site for radioactive waste disposal in West-Germany).
1971-1983
scientific employee: Institute of Geology and Paleontology of the University of Hannover - doctoral thesis on sedimentological questions of Upper Triassic sandstone formation in Lower Saxony.

Since 1983

freelancing consultant

Numerous expert opinions / publications in applied (hydro)geology and methodology (mostly in cooperation with other authors):

- selection, assessment and licensing of sites for final disposal of "conventional" and radioactive waste,
- risk assessment of (abandoned industrial) contaminated sites,
- site-specific and conceptual groundwater and soil protection in environmental impact assessment, water and soil management and planning,

Main clients: state authorities, regional/local water and environmental authorities, environmental NGOs (Greenpeace) and local environmental organizations.

Advisory activity

for German federal and state governments, environmental NGOs and local citizen action groups:

- Advisory Board on "Questions of Nuclear Power Phase-Out" of the Lower Saxony Ministry of the Environment (1992-1998),
- Committee on Site Selection Procedure of the Federal Ministry of the Environment, Nature Protection and Reactor-Safety (1999-2002),
- Working Group Fuel and Waste Management of the German Commission on Reactor-Safety,
- Radiation Protection Commission of BUND - Friends of the Earth,
- Scientific Advisory Board of the Konrad Mine Working Group.

International activities and cooperation

- Swiss Expert Group on Disposal Concepts for Radioactive Waste,

- Cantonal Working Group Wellenberg (Advisory Board of the Canton Nidwalden on safety aspects of the formerly planned LWA/MAW repository, Switzerland; until September 2002),
- Forum on Stakeholder Confidence (OECD/NEA),
- EC-Project COWAM (Community Waste Management),

Membership of scientific / professional associations

- German Geological Society,
- Society of Environmental Geosciences,
- Engineering-Technical Association on Contaminated Sites,
- Professional Society of German Geoscientists.

YURI V. DUBLYANSKY

EDUCATION	University of Perm, Russia: PhD (Candidate of Sciences) in Geosciences, 1987 University of Odessa, Ukraine: M.S. in Geological Engineering and Hydrogeology, 1982
WORK PLACE	Fluid Inclusion Lab. Institute of Mineralogy and Petrography, Russian Academy of Sciences, Siberian Branch, since 1985 to present
POSITION	Senior Scientist
WORK ADDRESS	Russia, 630090, Novosibirsk, 3, Koptyuga Ave. IM&P SB RAS Phone: +8-913-920-5263 (cel); FAX: +7-3832-332792 e-mail: kyoto_yuri@hotmail.com
SPECIALIZATION AND FIELD OF INTEREST	Geological disposal of nuclear waste; low temperature hydrothermal processes; fluid inclusions, isotope geochemistry. Analysis of the scientific and regulatory issues related to the geological disposal of the high-level nuclear waste.
LANGUAGES	English (fluent) and French (somewhat rusty)

PROFESSIONAL EXPERIENCE

2002 By request of the State of Nevada Attorney General Office, with the group of co-authors from USA, UK and Russia, writing a scientific monograph, providing independent evaluation of the suitability of the U.S. proposed site for geological disposal of the high-level nuclear waste at Yucca Mountain, Nevada. Monograph will be used by the State of Nevada as part of legal deposition in the forthcoming litigations, court hearings and licensing proceedings related to the Yucca Mountain high-level nuclear waste disposal site.

1999-2001 Official representative of the State of Nevada in the three-lateral (U.S. Department of Energy, State of Nevada and University of Nevada) research project on the paleo-hydrology of the proposed geological disposal site for the high-level nuclear waste at Yucca Mountain, Nevada. In this capacity testified before the presidential Nuclear Waste Technical Review Board and before the Advisory Committee on Nuclear Waste of the U.S. Nuclear Regulatory Commission.

Scientific leader and manager of the research project commissioned by the Government of the State of Nevada studying critical issues of the geological suitability of the proposed high-level nuclear waste site in Nevada.

1997 - 1998 Served as an expert to TACIS (a EC program), assessing geological issues of the nuclear waste disposal in the Northwest Russia. Performed critical evaluation of the concept of the nuclear waste disposal in permafrost on the Novaya Zemlia archipelago.

1994 - 1998 Consulting the State of Nevada's Nuclear Waste Project Office and the Attorney General Office on the issues of the geological suitability of the high-level nuclear waste repository at Yucca Mountain. Submitted 19 technical reports.

1993 - 1994 International Scientific Fellowship Award from NSERC, Canada, taken up at McMaster University, Hamilton, Ontario, Canada. Fluid inclusion and stable isotope geochemistry research.

1992 - 1993 Consulting the Hungarian National Authority for Nature Conservation on fossil hydrothermal systems and caves in Budapest and the Transdanubian Range.

RECENT PROFESSIONAL PUBLICATIONS PERTINENT TO THE NUCLEAR WASTE DISPOSAL

1. Dublyansky Y.V., Smirnov, S.Z., and Pashenko S.E. 2003 Identification of the deep-seated component in paleo fluids circulated through a potential nuclear waste disposal site: Yucca Mountain, Nevada, USA. *Journal of Geochemical Exploration*, **4013**, pp. 1-5. (*In press*)
2. Dublyansky, Y., Ford, D., and Reutski, V. 2001 Traces of epigenetic hydrothermal activity at Yucca Mountain, Nevada: preliminary data on the fluid inclusion and stable isotope evidence. *Chemical Geology*. **173**, pp. 125-149.
3. Dublyansky, Y. 2001 Paleohydrogeology of Yucca Mountain by Fluid Inclusions and Stable Isotopes. Proc. Int. Con., Amer. Nucl. Soc. "High-Level Radioactive Waste Management". La Grande Park, Illinois. CD ROM
4. Dublyansky, Y., Szymanski, J., Chepizhko, A., Lapin, B., and Reutski, V. 1999 Paleohydrogeology of Yucca Mountain (Nevada, USA): Key to the Site Suitability Assessment for Planed Nuclear Waste Repository. *Geoecology*. **1**, pp. 77-87. (In Russian)
5. Dublyansky, Y., Szymanski, J., Chepizhko, A., Lapin, B. and Reutski, V. 1998 Geological History of Yucca Mountain (Nevada) and the Problem of a High-Level Nuclear Waste Repository. *Defence Nuclear Waste Disposal in Russia*. NATO Series. Kluwer Academic Publishers, The Netherlands. pp. 279-292.
6. **Hill, C., Dublyansky, Y., Harmon, R., and Schluter, C. 1995 Overview of calcite/opal deposits at or near the proposed high-level nuclear waste site, Yucca Mountain, Nevada: pedogenic, hypogene, or both? *Environmental Geology*, 26(1), pp. 69-88.**

Prof. Dr. Gerhard Jentzsch Institute for Geosciences, University of Jena

Born in 1946 in Taucha near Leipzig, Germany

Education:

Habilitation for Geophysics, Free University of Berlin, 1985, Institute for Geophysical Sciences, Free University of Berlin.

Doctoral examination, Technical University of Clausthal, Germany, 1976, from Faculty for Geosciences, Institute for Geophysics.

Exam (Diploma) in Geophysics, 1972, same institute.

Current Employment:

1996-present: Full Professor for Applied Geophysics at the Institute for Geosciences of the University of Jena

Professional Societies:

German Geophysical Society (currently President of this society), Geologische Vereinigung, European Geophysical Union, American Geophysical Union

Employment history:

1990 - 1996: Professor for General Geophysics at the Institute for Geophysics, Technical University of Clausthal.

1987 – 1990: Professor for Applied Geophysics (Angewandte Geophysik) at the Geological Institute of the University of Bonn.

1977 – 1987: Assistant at the Institute for Geophysical Sciences, Free University of Berlin, Assistence Professor (Hochschulassistent)

1972 – 1977: scientific co-worker of Prof. Dr. O. Rosenbach, Institute for Geophysics

Consulting Experience, 1990 – present:

Seismic hazard assessment for the sites of different nuclear power plants and nuclear industry in Germany, in the form of:

- check of reports
- own calculations
- member of advisory board

1999 – 2002 Member of the German siting committee to develop a procedure for the search for a site of the German nuclear repository (appointed by the German Federal Ministry of the Environment)

1993 – 1998 Member Advisory Board for the Termination of Nuclear Energy Use (Provincial Ministry for the Environment of Lower Saxony)

Additional information:

Research Interests: deformation and seismology (Earth tides, global dynamics, seismological network in East-Thuringia, Geodynamic Observatory Moxa), seismic hazard assessment, physical volcanology

Publications: more than 40 papers during the past 5 years; 15 of them in reviewed journals

National and international activities:

Chairman of working groups (IAG), convenor of special sessions (EGS Meetings, Earthtide Symposium, national meetings), reviewer for the German Research Soc. and different scientific journals

Currently: President of the German Geophysical Society

Publications relating to seismicity / deformation and nuclear waste repository:

1. Nuclear waste repositories:

AKEnd: Arbeitskreis Auswahlverfahren Endlagerstandorte des BMU, 2000. 1. Zwischenbericht, Stand: Juni 2000. Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU), Referat RS III 4 (A), 54 S. First intermediate report.

Bräuer, V. und G. Jentzsch, 2001. Abgrenzung von Gebieten mit offensichtlich ungünstigen geologischen Verhältnissen. Bericht an den AkEnd. Separation of areas with obvious unfavourable geological conditions.

Jentzsch, G., 2001. Vulkanische Gefährdung in Deutschland. Bericht an den AkEnd. Volcanic hazard in Germany.

AKEnd: Arbeitskreis Auswahlverfahren Endlagerstandorte des BMU, 2001. 2. Zwischenbericht – Stand der Diskussion. Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU), Referat RS III 4 (A), 179 S. Second intermediate report.

Appel, D., V. Bräuer, G. Jentzsch und K.-H. Lux, 2002. Geowissenschaftliche Kriterien zur Endlagerstandortsuche für radioaktive Abfälle – Ergebnisse des Arbeitskreises Auswahlverfahren Endlagerstandorte. Z. Angew. Geol, 2/2002, 40 – 47. Geoscientific criteria for the seek of a repository for radioactive waste – results of the AkEnd.

AKEnd: Arbeitskreis Auswahlverfahren Endlagerstandorte des BMU, 2002. Auswahlverfahren für Endlagerstandorte – Empfehlungen des AkEnd. Abschlussbericht, Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU), Referat RS III 4 (A), 260 S. Final report.

Jentzsch, G., 2002. Temperaturverträglichkeit der Gesteine - Neigung zur Ausbildung von Wasserwegsamkeiten. Bericht an den AkEnd. Temperature acceptance of rocks – tendency to open transport paths for fluids.

2. Seismology and deformation

Kracke, D., R. Heinrich, G. Jentzsch, and D. Kaiser, 2000. Seismic Hazard assessment of the East Thuringian Region / Germany – case study. Studia Geophysica et Geodaetica, 44/4, 537 – 548.

Kracke, D., R. Heinrich, A. Hemmann, G. Jentzsch, and A. Ziegert, 2000. The East Thuringia Seismic Network. Studia Geophysica et Geodaetica, 44/4, 594 – 601.

Hemmann, A., T. Meier, G. Jentzsch and A. Ziegert, 2000. A similarity of wave-forms at stations Moxa and Plauen for the 1985/86 swarm. Studia Geophysica et Geodaetica, 44/4, 602 – 607.

Kroner, C., T. Jahr, G. Jentzsch, W. Zürn, R. Widmer-Schniedrig, and B. Heck, 2000. BFO and Moxa: Two observatories for seismological broadband observations. Orfeus Newsletter, Dez. 2000, Vol. 2, No. 3.

Jahr, T., Jentzsch, G., Kroner, C., 2001. The Geodynamic observatory Moxa / Germany: Instrumentation and purposes. Proc. 14th International Symposium on Earth Tides, Special Issue J. Geodetic Soc. of Japan, 47/1, 34 – 39.
Ishii, H., Jentzsch, G., Graupner, S., Nakao, S., Ramatschi, M. and Weise, A., 2001. Observatory Nokogiriyama / Japan: Comparison of different tiltmeters. Proc. 14th International Symposium on Earth Tides, Special Issue J. Geodetic Soc. of Japan, 47/1, 155 – 160.
Jentzsch, G., Malischewsky, P., Zaddro, M., Braitenberg, C., Latynina, A., Bojarsky, E., Verbytzkyy, T., Tikhomirov, A. and Kurskeev, A., 2001. Relations between different geodynamic parameters and seismicity in areas of high and low seismic hazards. Proc. 14th International Symposium on Earth Tides, Special Issue J. Geodetic Soc. of Japan, 47/1, 82 – 87.
Gutdeutsch, R., D. Kaiser, and G. Jentzsch, 2002. Estimation of earthquake magnitudes from epicentral intensities and other focal parameters in Central and Southern Europe. Geophys. J. Int., 151(3), 824 - 834.
Jentzsch, G. S. Graupner, A. Weise, H. Ishii, and S. Nakao, 2002. Environmental effects in tilt data of Nokogiriyama Observatory (extended abstract). Bulletin d'Information Marees Terrestres, 137, 10931 - 10936.
Jentzsch, G., M. Korn, and A. Špičák (eds.), 2003. The swarm earthquakes in the area Vogtland / NW-Bohemia: Interaction of tectonic stress and fluid migration in a magmatic environment. Special Issue J. Geodyn., 35, 1 / 2, 258 p.
Jentzsch, G., M. Korn, and A. Špičák, 2003. Editorial. In: Jentzsch, G., M. Korn, and A. Špičák (eds.): The swarm earthquakes in the area Vogtland / NW-Bohemia: Interaction of tectonic stress and fluid migration in a magmatic environment. Special Issue J. Geodyn., 35, 1 / 2, 1 -3.
Kurz, J., T. Jahr und G. Jentzsch, 2003. Geodynamic modelling of the recent stress and strain field in the Vogtland swarm earthquake area using the finite-element method. In: Jentzsch, G., M. Korn, and A. Špičák (eds.): The swarm earthquakes in the area Vogtland / NW-Bohemia: Interaction of tectonic stress and fluid migration in a magmatic environment. Special Issue J. Geodyn., 35, 1 / 2, 247 – 258.
Hemmann, A., T. Meier, G. Jentzsch, and A. Ziegert, 2003. Similarity of waveforms and relative relocation of the earthquake swarm 1997/98 near Werdau. In: Jentzsch, G., M. Korn, and A. Špičák (eds.): The swarm earthquakes in the area Vogtland / NW-Bohemia: Interaction of tectonic stress and fluid migration in a magmatic environment. Special Issue J. Geodyn., 35, 1 / 2, 191 – 208.

Curriculum Vita of Mike Thorne

Qualifications PhD FSRP

KEY SKILLS

- Radiological protection
- Assessing the radiological safety of disposal of radioactive wastes
- Distribution and transport of radionuclides in the environment
- Expert elicitation procedures
- Probabilistic safety studies
- Development of safety criteria
- Pharmacodynamics

CAREER HISTORY

2001- **<u>Mike Thorne and Associates Limited</u>**

Review Studies for the Proposed Australian National Radioactive Waste Repository

Client – RWE NUKEM

Reviews of reports on animal transfer factors and of the potential effects of climate change on the repository plus development of a model for the biokinetics of the ^{226}Ra decay chain in grazing animals.

Support for development of the Drigg Post-closure Radiological Safety Assessment

Client - BNFL

Support in the areas of FEP analysis, biosphere characterisation, human intrusion assessment and the effects of natural disruptive events. In addition, provision of advice of future research initiatives that should be pursued by BNFL.

Co-ordination of biosphere research and participation in BIOCLIM

Client – UK Nirex Ltd

Review of Parameter Values: Review of biosphere parameter values for use in the ANDRA assessment model AQUABIOS.

Effects of Radiation on Organisms Other Than Man

Client: Study for ANDRA to identify appropriate indicator organisms and develop appropriate dosimetry and effects models for those organisms.

Evaluation of Unusual Pathways for Radionuclide Transport from Nuclear Installations
Client – Environment Agency

Review of literature and conduct of formal elicitation meetings to determine potential pathways and evaluate their radiological significance.

Support Studies on the Drigg Post-closure Performance Assessment
Client - BNFL
Biosphere Research Co-ordination and Assessment Studies
Client - United Kingdom Nirex Ltd

Continuation of a programme of work originally undertaken at Electrowatt Engineering (UK) Ltd

Site Investigation and Risk Assessment - Hilsea Lines
Client - Portsmouth City Council
Radiological assessment of a radium-contaminated site.

PROFESSIONAL ACTIVITIES AND MEMBERSHIP

- Fellow of the Society for Radiological Protection and Immediate Past President
- Member of the Eco-ethics International Union
- Visiting Fellow at the Climatic Research Unit, University of East Anglia

SELECTION OF PUBLICATIONS

The biosphere in post-closure radiological safety assessments of solid radioactive waste disposal, M C Thorne, Interdisciplinary Science Reviews, Vol. 23, 258-268, 1998.

Modelling radionuclide distribution and transport in the environment, K M Thiessen, M C Thorne, P R Maul, G Prohl and H S Wheater, Environmental Pollution, 100, 151-177, 1999.

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Development of a solution method for the differential equations arising in the biosphere module of the BNFL suite of codes MONDRIAN, M M R Williams, M C Thorne, J G Thomson and A Paulley, Annals of Nuclear Energy, 29, 1019-1039, 2002.

Modelling sequential BIOsphere Systems under CLIMate change for radioactive waste disposal. Project BIOCLIM, D Texier, P Degnan, M F Loutre, D Paillard and M Thorne, Proceedings of the 10th International High-level Radioactive Waste Management Conference (IHLRWM), March 30th – April 2nd, Las Vegas, Nevada.

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Feature

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The Growing Problem of Stranded Used Nuclear Fuel

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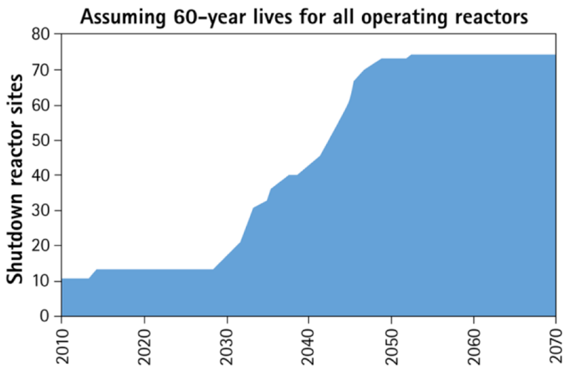

By 2050, almost all U.S. nuclear reactors will have reached their 60 year maximum expected life. Many will shut down sooner. With no assurance that the current approach for finding a geologic repository or interim storage sites will succeed, used nuclear fuel could be stranded indefinitely at more than 70 sites in 35 states. Societal discussions about the future of nuclear waste should be framed in terms of the relative risks of all alternatives. We review and compare onsite storage, interim storage, and a geologic repository, as well as how these alternatives are presented to the public.

INTRODUCTION

There are 10 decommissioned nuclear power plants in the U.S. where the used (spent) fuel remains stranded onsite.[1] In 2013, operators of three additional nuclear plants announced permanent shutdowns. By 2050, virtually all U.S. commercial nuclear reactors will have reached their 60 year maximum expected life.

In 2009, after decades of work and over $10 billion spent, the Obama administration announced that it would terminate the nation's only proposed repository for used nuclear fuel and other high-level waste at Yucca Mountain, Nevada. In August 2013, a federal court ordered the Nuclear Regulatory Commission to complete its review of the Yucca Mountain license application,[2] but the project remains mired in controversy.

Even if a geologic repository opened tomorrow, it would take decades to move all of the used fuel to the repository.[3] The track record for transporting radioactive wastes is good,[4] yet any large-scale plan for moving used nuclear fuel will be a flash point for opposition. Even under the best of circumstances, it will take a long time to develop coordination among states of travel routes, security, emergency preparedness, safety inspections, monitoring of shipments, and public information.

It is likely that within a few decades used nuclear fuel will be stranded indefinitely at more than 70 sites in 35 states (Figure 1). The Nuclear Regulatory Commission (NRC) is evaluating the possibility of onsite storage for as long as 300 years.[1] The recent NRC draft generic environmental impact statement on waste confidence includes the possibility of indefinite surface storage in the event that a geologic repository never becomes available.[5]

While we focus on used fuel from commercial reactors, high-level radioactive waste from the nuclear weapons program also is destined for deep geologic disposal, as is vitrified high-level waste from the former reprocessing plant at West Valley, New York.[6] Finally, geologic disposal is required to address the nonproliferation risks from separated weapons plutonium, after being irradiated as mixed oxide (MOX) fuel.[7]

Advanced fuel cycle technologies and reprocessing potentially can reduce the volume, heat, and toxicity of these wastes, yet a geologic repository will be required for all fuel cycles. Advanced fuel cycles also continue to be stymied by economic and technical challenges, and are decades away from commercial implementation. Given these factors, virtually every expert panel having studied the problem has concluded that geologic disposal efforts should not be delayed by the promise of future unproven technology.[1,8]

The current stalemate affects prospects for nuclear energy to help meet the world's growing energy needs while combating climate change. It is increasingly difficult to make the case for a new nuclear plant when the waste from the last plant has nowhere to go.

ONSITE STORAGE

Two options are available for storing used fuel—wet storage in pools and dry storage in casks. During the first five years after discharge from a reactor, used fuel assemblies require active cooling in pools to prevent damage to the fuel. These pools are increasingly packed, as a result of the nuclear waste backlog. By 2017, the used fuel pools at all but one site are expected to be at capacity.[9]

Gradually, used fuel is being moved to dry casks. While there has been considerable debate about the risks of increasingly packed pools,[10,11] less attention has been given to the risks of indefinite onsite storage in dry casks.

Dry casks typically consist of a metal canister surrounded by a concrete overpack. The canisters are loaded underwater in the storage pool, the water is pumped out, and the canister is filled with helium to prevent degradation by oxidation. Lids are bolted or welded on. The canister is then transported to an outdoor concrete storage pad where it is loaded into the concrete overpack. Fully loaded, each cask weighs 150 tons or more. Natural convection through vents in the concrete or via cooling fins on bolted metal casks provides passive cooling by ambient air.

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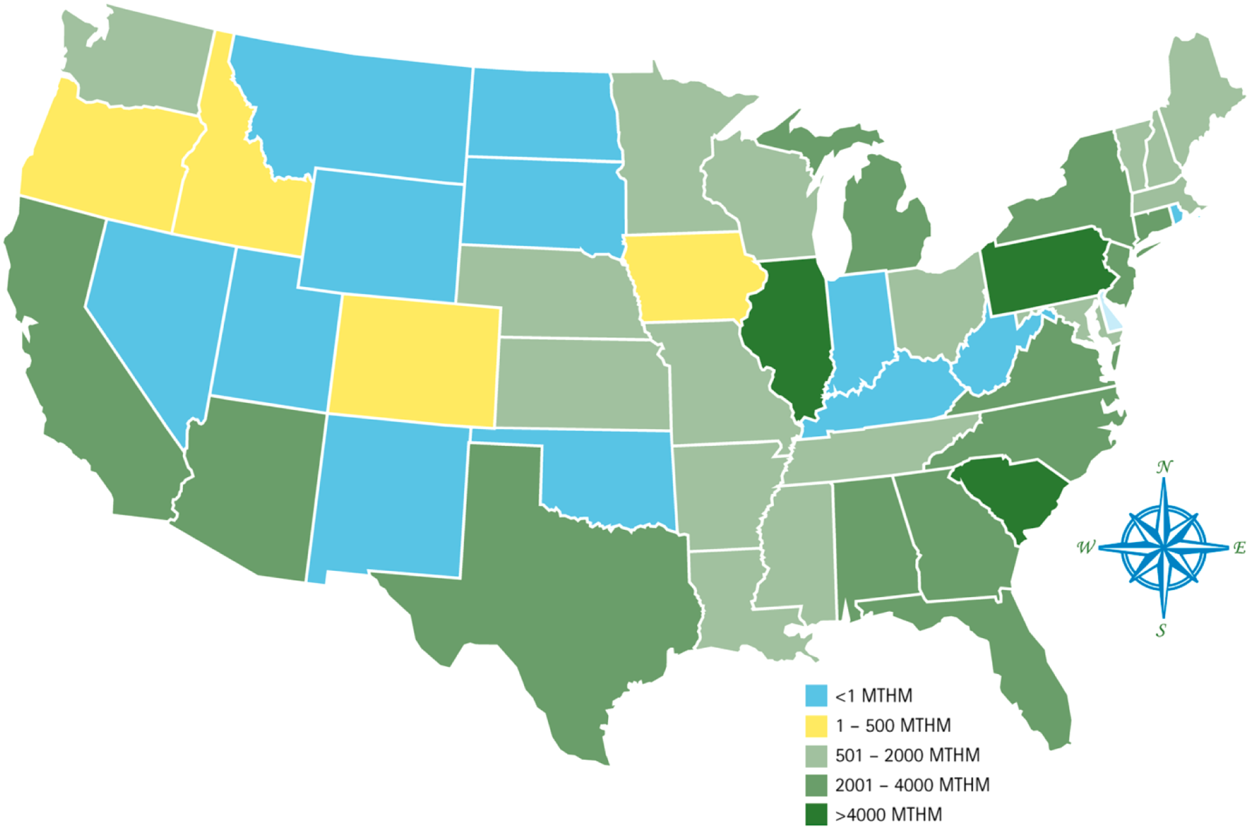

Figure 1. Used nuclear fuel storage in metric tons of heavy metal (MTHM) in each state at the end of 2012. Three states (Illinois, Pennsylvania, and South Carolina) collectively have more than one-quarter of the used fuel. Data from Nuclear Energy Institute.

The confidence in dry casks rests on their passive and robust nature, studies of individual components, and a full-scale study that opened and examined a 15-year old dry cask containing low burn-up fuel.[12] In recent years, improvements have been made in fuel technologies that have allowed plant operators to achieve higher burn-up levels, almost doubling the amount of energy captured. The Nuclear Waste Technical Review Board, a presidentially appointed oversight group, concluded that the technical basis for extended (>60 year) dry cask storage of today's high burn-up fuel is not well established and that several degradation mechanisms require more study.[13] Among these, high burn-up fuels may result in the fuel cladding becoming brittle with time.[14] After the shutdown of Yucca Mountain, the Electric Power Research Institute initiated an R&D program investigating key issues with extended storage.[15] Meanwhile, placement of used fuel in dry casks is well underway with more than 1700 casks in 34 states at the end of 2012.[5]

Dry casks can play an important role as part of a responsible nuclear waste disposal program, but open-ended onsite storage raises concerns. The limited ability to monitor conditions within the sealed canisters becomes problematic in the long term, particularly with respect to fuel retrievability. Thus, new technologies for monitoring the interior of dry casks are under development.[16] Questions also remain about how the used fuel could be removed for inspection or the casks changed out, if problems develop after the pools are gone.

The marginal cost of storing used fuel on a site with ongoing nuclear operations is relatively low, because most of the storage costs can be integrated with existing site operations. However, at sites with no current nuclear operations, the annual cost of used fuel storage is about $8 million per site.[17]

Ideally, an integrated plan for storage, transportation, and disposal would be laid out in advance. Design of the canisters would account for allowable canister size and thermal loads for disposal; however, these features cannot be determined without knowing the specific requirements of the geologic repository. Dual-purpose casks are licensed for both storage and transportation of nuclear waste, although their large size may pose problems for direct disposal with respect to factors such as criticality and thermal load. Storage-only casks, which are not suitable for transportation, will require repackaging prior to shipment or special exemptions from the NRC.

Eventually, there is another crucial issue. After a century or so, the used fuel's radioactivity will diminish to where it no longer presents a significant barrier to the plutonium.[1,8] Thus, extended surface storage presents an increasing nuclear proliferation risk.

A substantive analysis comparing the risks of extended onsite storage with those of a geologic repository has never been done, although a draft generic environmental impact statement recently has been completed that provides some progress in this direction.[5] In 2007, the Nuclear Regulatory Commission conducted a pilot study to develop a methodology for risk assessment of dry cask storage.[18] The pilot study estimated very low risk.

In summary, while the current risks of dry casks appear to be low, today's stranded waste could result in significant long-term problems for our descendants. Storing used fuel at decommissioned sites is costly. In addition, the lack of a geologic repository affects the ability to develop an integrated plan for storage, transportation, and disposal, resulting in future costs for repackaging and additional risk.

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Table 1. Key Advantages and Disadvantages of Yucca Mountain and Three Alternate Rock Types for Disposal of High-Level Nuclear Waste

rock type	key advantages	key disadvantages
Yucca Mountain unsaturated tuff	relative ease of retrievability, arid/semiarid climate, remote federal lands, closed basin, lack of mineral deposits, stable mining, high thermal conductivity, zeolites for sorption	tectonically active area, oxidizing environment, fractured rock difficult to characterize
crystalline rock (granite)	lack of mineral deposits, stable mining, thermally stable, widespread occurrence	difficult to characterize transmissive fractures at repository scale, weak sorption/diffusion
shale	very low permeability, high sorption capacity, self-sealing	potential gas buildup, mining challenges, potential for permeable faults, relatively poor heat transfer
salt	absence of flowing water, very low permeability, self-sealing, high thermal conductivity	effects of heat on moisture movement, difficult to retrieve wastes, potential gas buildup, risk of future drilling for resources (oil, gas, potash), low sorption capacity

INTERIM STORAGE

In 1996, the Nuclear Waste Technical Review Board concluded there were no compelling technical reasons for moving commercial used fuel to a consolidated interim storage facility.[19] The Board viewed the risks to be essentially the same for at-reactor and interim storage. With pressure continuing to build from the current impasse in licensing a geologic repository, interim storage has become more appealing.[1,20] The U.S. Department of Energy proposes to have a "pilot" interim storage facility in operation by 2021 to store used fuel from decommissioned reactors. A larger interim storage facility is planned for operation beginning in 2025.[21]

Interim storage has several key advantages. The federal government could take charge of the waste, thereby reducing the lawsuits by utilities after the government failed to honor its commitment to begin taking charge of used fuel by 1998. The waste could be moved from populated areas. An interim site would reduce the cost and security burdens of onsite stranded waste. In addition, proponents of nuclear energy could claim progress with at least some aspect of nuclear waste disposal.

Yet is interim surface storage any more possible, or palatable, than geologic disposal? Would it undermine the search for a geologic repository? What are the risks of moving the waste twice? And how *interim* is interim?

Interim storage is not a new idea.[22] In the early 1970s, the Atomic Energy Commission (AEC) proposed constructing a surface storage facility at one or more existing nuclear sites to temporarily store high-level waste while other options were pursued. The AEC was forced to back down when environmental groups argued that the storage facility could easily become a de facto repository.

In 1982, the Nuclear Waste Policy Act (NWPA) provided for development of a long-term "monitored retrievable storage" facility. The community of Oak Ridge, Tennessee expressed interest until statewide opposition shut it down.

The 1987 Amendments to the NWPA established a Nuclear Waste Negotiator who made every effort, but failed to find a volunteer for an interim storage site. A handful of communities expressed interest, only to be blocked by their governors.

In the 1990s, the Skull Valley Band of Goshute Indians volunteered to host an interim facility on its reservation in Utah. After more than 15 years of legal battle with the state and the Department of the Interior, the NRC-approved site was abandoned in 2012.

Lack of progress toward a geologic repository makes finding an interim storage site even more difficult. The NWPA amendments expressly forbid opening an interim storage site until a repository is under construction, to ensure that the interim site does not become a de facto repository far into the future.[23]

In summary, while the growing problem of stranded nuclear waste makes interim storage at a centralized site more appealing, there are continuing concerns that interim storage sites could remove incentives for finding a geologic repository and no assurance that such sites are any easier to find than a geologic repository.

DISPOSAL IN A DEEP GEOLOGIC REPOSITORY

The concept of a geologic repository comes to mind almost instinctively—bury the waste deep underground (300−800 m) in mined cavities or tunnels to isolate it from the biosphere and from inadvertent or malicious intrusion by humans. Deep boreholes drilled several kilometers into crystalline basement rocks also have been proposed, although less thoroughly investigated.[1,24,25]

Despite 435 nuclear power reactors in 31 countries[26] and the worldwide scientific consensus on the need for geologic disposal, no geologic repositories for used nuclear fuel exist anywhere in the world.[27] Finland and Sweden have made substantial progress toward developing geologic repositories and expect operations to begin in the 2020−2025 time frame.[28] Other countries, such as the United States, Canada, Germany, Japan, and the U.K., have fallen far behind with no current sites selected for assessment (beyond Yucca Mountain in the U.S.). Meanwhile, the World Nuclear Association reports that 45 countries without nuclear power are giving it serious consideration.[29] Several others, including China, South Korea, and India, are planning to massively expand their existing programs.

According to the International Atomic Energy Agency, a permanent waste repository must provide sufficient isolation so "that eventual releases of radionuclides will be in such low concentrations that they do not pose a hazard to human health and the natural environment."[30] Decades of research and site investigations suggest that a variety of rock types and geologic environments, in combination with appropriate repository design, might be suitable for achieving this objective.[1,30,31]

Rock types currently considered for a deep geologic repository include salt, crystalline rocks (i.e., granite or gneiss), argillaceous formations (shale, mudrocks, and clays), and volcanic tuff. Each rock type has its strengths and weaknesses (Table 1), but none are perfect.

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The uncertainty in long-term repository performance is offset, in part, by adopting a defense-in-depth philosophy, whereby the repository safety does not depend on the performance of any single barrier. Multiple barriers comprise both natural and engineered barriers. Natural barriers comprise the geologic system's capability to dilute, retard, and even retain radionuclides during transport. The engineered barrier system includes the waste form, the canister or waste package, and any backfill. While the principal challenge with natural barriers is in characterizing the local geology, the principal difficulty with engineered barriers is the lack of data on their long-term performance.

Engineered barriers are designed to contain the waste during the initial period of highest radiological toxicity. However, no matter how robust the engineered barrier system might be, it is virtually guaranteed to eventually fail. At this juncture, waste containment relies solely on the natural system. The relative roles of the barriers may vary. For example, the natural system is considered the major barrier in shale and clay, while the main role of the natural system in the granitic rocks of Sweden and Finland is to provide a chemically and mechanically stable environment for the engineered barriers.[32]

In the early years of the Yucca Mountain studies, it was believed that the regulatory standards could be achieved without additional engineered barriers.[33] By the late 1990s, the engineered barrier system dominated the waste isolation safety case after bomb-pulse levels of chlorine-36 were found in the exploratory tunnels.[34] The chlorine-36 results were never confirmed,[22] yet the abrupt about-face from the dependence on the natural to the engineered barriers dealt a substantial blow to the project's credibility.[35]

The most fundamental challenge in making the safety case is that nuclear waste remains dangerous over timeframes beyond human experience and even our comprehension. The principal means of addressing this problem has been through mathematical modeling to simulate the long-term behavior of the geologic repository to features, events, and processes that could conceivably contribute to its eventual failure.[36] Known as performance assessment, the approach requires hundreds of component models with thousands of input parameters. Each model (climate change, groundwater flow, used fuel corrosion, etc.) presents a major challenge to represent processes ranging from molecular to regional scales. The output of one model serves as input to others, often involving coupled processes. Methods of uncertainty analysis are used to assess effects of parameter and conceptual uncertainties on the uncertainty in simulated outcomes.

There is general agreement that performance assessment is useful to evaluate the relative risk of different repository designs, identify data needs, and provide insights on long-term behavior as qualitative information. Controversy arises when performance assessment is used to compare model predictions with regulatory standards up to one million years in the future—a time frame that is at odds with what most geoscientists believe that science can provide.[22,36] Aside from the technical challenges, many highly subjective aspects place constraints on analyzing a problem with this time frame. Where do people live? What do they eat and drink? How might contaminated and uncontaminated groundwater mix in their well? What is their use of the water?

Given that it is not good enough to simply say that a site "looks safe," some sort of model analysis and comparison to standards is required. There appears to be general consensus that a prescriptive regulatory regime, based on direct comparison of performance assessment results with regulatory standards for the first few thousand years, is a necessary part of the safety case.[37] It is beyond this period where opinions diverge.[38]

Field-based studies and underground research laboratories play a critical role in demonstrating fundamental understanding of the natural system.[27,39,40] Particularly compelling evidence comes from natural analogues of repository behavior over geologic timeframes. These analyses also may be more easily understood by the public. For example, uranium deposits at Peña Blanca in Chihuahua, Mexico, provided a natural analogue for the long-term behavior of uranium in used fuel in the unsaturated volcanic tuff at Yucca Mountain.[41] Very low permeability in clay and shale can be demonstrated by anomalous pressures that are still responding to forcing by geologic processes, such as glacial ice load changes.[42] In addition, natural tracers such as chloride ions and stable isotopes measured in pore waters of shale and clay have been shown to attain their present distributions by diffusion over millions of years.[42,43] Studies of naturally occurring radon, radium, and helium have been used to study molecular diffusion in matrix pore water and connectivity to water in fractures at scales up to millions of years in the deep granitic rocks of Sweden and Finland.[44]

Following recommendations of the Blue Ribbon Commission on America's Nuclear Future, the U.S. is in the beginning stages of a consent-based approach to find a community willing to host an interim storage site or geologic repository.[1,21] As demonstrated by the history of interim storage, finding a volunteer community is the relatively easy part. States, which share fewer benefits than local communities, are much more difficult to convince. Officials of Nye County, Nevada, which encompasses Yucca Mountain, have consented to host the proposed repository, while the state of Nevada remains vehemently opposed. Similarly, in the U.K., two local communities near the Sellafield nuclear complex are in favor of taking the next steps toward siting a repository, yet were recently overruled by their County Council.[45]

Given that public acceptance is the Achilles' heel of nuclear waste disposal, the manner in which the safety case is presented to the public is of primary importance. Developing the technical basis for a repository is a decades-long process that should be undertaken with no predetermined outcome.[46] From the outset, humility is needed about the uncertainties involved. Unanticipated findings, such as the chlorine-36 findings at Yucca Mountain, may require major adjustments. The Board on Radioactive Waste Management of the National Research Council forewarned decades ago that surprises inevitably occur and setting unrealistic expectations for prior knowledge of a geologic repository risks undermining public trust.[47]

For more than 25 years, Yucca Mountain has been the sole candidate for a geologic repository, resulting in no plan B and no other geologic settings for comparison within the U.S. The United States is also the only country in the world to have set a deadline (January 31, 1998) for opening a high-level waste repository, contributing to a perception that meeting deadlines was more important than thoughtful deliberation.[35]

Lessons can be learned from the Waste Isolation Pilot Plant (WIPP) in New Mexico—the world's only operational geologic repository for long-lived (but not high-level) radioactive wastes. The success of WIPP is in part attributed to an independent, technical group who advised the state on possible health and

safety impacts of the proposed repository and ensured that important technical issues would be addressed in a rigorous fashion.[48] There is no comparable group for Yucca Mountain. The Nuclear Waste Technical Review Board has proved advantageous in raising key technical areas, yet its purpose is to advise the President and Congress, not to represent concerns of the affected communities, tribes, and states.

There never will be complete agreement among scientists about future repository performance, nor will all questions be answered. However, some degree of consensus within the scientific community is necessary to build credibility with the public. Such a consensus was not fully achieved at Yucca Mountain. In future studies, greater emphasis should be given to the refereed scientific literature and to fostering more open debate among scientists both within and outside the project.

■ CONCLUDING REMARKS

Solving the nuclear waste dilemma requires staying the course over decades with a technically complex and politically sensitive program. It also requires decisiveness in the face of unprecedented long-term uncertainty. While it is widely accepted among experts in nuclear waste management that the waste problem is solvable, this view is not shared by the public at large.[8]

When viewed in isolation, almost any approach for dealing with used nuclear fuel will be viewed as unacceptable by a large segment of society.[49] Thus all options, including the status quo, should be publically addressed and the risks of each option openly acknowledged.

Transfer of used nuclear fuel to a geological repository is, at best, decades away with indefinite onsite storage a growing possibility. While the risks of dry casks appear to be low for the short-term, today's stranded waste could pose significant problems for our descendants. Open recognition of the risks of indefinite onsite storage could lead to greater societal awareness of the need for a repository.

Given the length of time required to study a potential repository, coupled with an uncertain outcome, the United States should pursue interim storage and investigate multiple sites for a repository, as advocated by the Blue Ribbon Commission.[1] With so much invested, Yucca Mountain should remain an option, as others are sought. The tactics must change; however, with an open-ended dialogue addressing Nevadan's concerns. In the meantime, any community volunteering for an interim storage site should be aware of the open-ended time frame of such a facility. In this respect, *consolidated surface storage* may be a less misleading term.

Replacing the top-down approach with a consent-based policy could help break the current deadlock, yet a policy change is only a first step. Several decades ago, science writer Luther Carter argued that, "trust will be gained by building a record of sure, competent, open performance that gets good marks from independent technical peer reviewers and that shows decent respect for the public's sensibilities and common sense."[50] These ingredients do not ensure success, but in their absence, failure is guaranteed.

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Notes

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NUREG-1713

Standard Review Plan for Decommissioning Cost Estimates for Nuclear Power Reactors

Final Report

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COMMENTS ON DRAFT REPORT

Standard Review Plans (SRPs) are issued to describe and make available to the public information such as methods acceptable to the NRC staff for implementing specific parts of the NRC's regulations, techniques used by the staff in evaluating specific problems or postulated accidents, and data needed by the NRC staff in its review of applications for permits and licenses. This standard review plan was issued as a draft for public comment in November 2001. Based on use of this document and the public comments provided on the November 2001 version, the SRP has been revised.

This SRP guides the NRC staff in performing a review of each of the decommissioning cost estimates that licensees are required to submit in accordance with 10 CFR 50.75, "Reporting and Recordkeeping for Decommissioning Planning," and 10 CFR 50.82, "Termination of License." The principal purpose of the SRP is to ensure the quality and uniformity of NRC staff reviews and to present a well-defined base from which to evaluate the decommissioning cost estimates that are submitted before decommissioning and at various phases of the decommissioning process. It is also the purpose of the SRP to make the information about regulatory matters widely available so that interested members of the public and the nuclear industry can gain a better understanding of the staff's review process. The SRP identifies the matters to be reviewed, the basis for the review, and the conclusions that are sought.

SRPs are not substitutes for Regulatory Guides or the Commission's regulations, and compliance with them is not required. SRPs are initially issued in draft form for public comment to involve the public in the early stages of developing regulatory positions. Published SRPs will be revised periodically, as appropriate, to accommodate comments and to reflect new information and experience.

ABSTRACT

This Standard Review Plan (SRP) for decommissioning cost estimates provides guidance to Office of Nuclear Reactor Regulation (NRR) and Office of Nuclear Material Safety and Safeguards (NMSS) staff on how to evaluate each of the decommissioning cost estimates that are required to be provided by the power reactor licensees. The SRP includes guidance on evaluating decommissioning costs for both pressurized water reactors (PWRs) and boiling water reactors (BWRs). The SRP is divided into sections that are keyed to the sections in Regulatory Guide-1085, "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors," which was developed to provide guidance to licensees on decommissioning cost estimates. Each section of this NUREG is a separate SRP and presents the areas of review, acceptance criteria, review procedures, and evaluation findings for each of the decommissioning cost estimates required by 10 CFR 50.75 and 10 CFR 50.82.

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A. INTRODUCTION

Decommissioning means permanently removing a nuclear facility from service and reducing radioactive material on the licensed site to levels that permit termination of the NRC license. This Standard Review Plan (SRP) is divided into sections that are keyed to the sections in Regulatory Guide-1085, "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors," which is being developed to provide guidance to licensees on decommissioning cost estimates.

NUREG-0586, "Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities, Supplement 1," dated October 2002, evaluated the environmental impact of three methods for decommissioning. The supplemental information to the 1988 decommissioning rule (53 FR 24019) also discussed the three decommissioning methods. A short summary of the three methods follows.

DECON: The equipment, structures, and portions of the facility and site that contain radioactive contaminants are removed or decontaminated to a level that permits termination of the license after cessation of operations.

SAFSTOR: The facility is placed in a safe, stable condition and maintained in that state (safe storage) until it is subsequently decontaminated and dismantled to levels that permit license termination. The determination of SAFSTOR includes those activities necessary for the final decontamination and dismantlement of the facility. During SAFSTOR, a facility is left intact or may be partially dismantled, but the fuel has been removed from the reactor vessel and radioactive liquids have been drained from systems and components and then processed. Radioactive decay occurs during the SAFSTOR period, thus reducing the quantity of contamination and radioactivity that must be disposed of during decontamination and dismantlement (D&D). The definition of SAFSTOR includes the decontamination and dismantlement of the facility at the end of the storage period.

ENTOMB: Radioactive structures, systems, and components are encased in a structurally long-lived substance such as concrete. The entombed structure is appropriately maintained, and monitored until the radioactivity decays to a level that permits termination of the license. Because most power reactors will have radionuclides in concentrations exceeding the limits for unrestricted use even after 100 years and because current regulations require that decommissioning be completed within 60 years of cessation of operation, entombment requests will be handled on a case-by-case basis.

The NRC recognizes that some combination of these methods would also be acceptable. For example, the licensee could conduct a partial radiological decontamination of the plant followed by entombment or a storage period, followed by the completion of the radiological D&D. NUREG/CR-5884 and NUREG/CR-6174 describe two possible scenarios for evaluating the SAFSTOR decommissioning method: SAFSTOR1 and SAFSTOR2. For this SRP, the SAFSTOR2 scenario is assumed where all materials that were originally radioactive still exceed unrestricted release levels and are removed for disposal as low-level waste (LLW). This option results in a more conservative (higher) decommissioning cost estimate than the SAFSTOR1 scenario, which assumes most of the radioactive materials have decayed to unrestricted release levels.

On July 29, 1996, a final rule was published in the *Federal Register* (61 FR 39278) amending the NRC's regulations on the decommissioning procedures that will lead to termination of an operating license for nuclear power reactors. This final rule included changes to 10 CFR Parts 2, 50, and 51.

The revised regulations contain requirements related to decommissioning cost estimates. Regulatory Guide-1085 was written to provide guidance to licensees on the preparation of these cost estimates and to establish a standard format for reporting these cost estimates that is acceptable to the NRC staff.

The guidance in RG-1085 and this SRP apply only to power reactor licensees. The regulations for nonpower reactor licensees are given in 10 CFR 50.82(b).

The minimum decommissioning funding required by the NRC reflects only the efforts necessary to terminate of the Part 50 license. Other activities related to facility deactivation and site closure, including operation of the spent fuel storage pool, construction and operation of an independent spent fuel storage installation (ISFSI), demolition of decontaminated structures, and site restoration activities after residual radioactivity has been removed are not included in the NRC definition of decommissioning. Accordingly, costs for such "nondecommissioning activities" are not addressed in this SRP; however, costs associated with the decontamination of an ISFSI licensed under the general license are included.

B. DISCUSSION

NRC decommissioning funding requirements can be segregated into two categories: (1) those that specify the minimum decommissioning fund that power reactor licensees must obtain and/or maintain to demonstrate reasonable assurance of having adequate funds to decommission their facilities, and (2) those that specify when licensees must submit decommissioning requirements governing site-specific cost estimates. Both sets are relevant to this SRP and are discussed below.

1. FINANCIAL ASSURANCE

Licensees of operating nuclear power reactors must provide reasonable assurance that funds will be available for the decommissioning process. For these licensees, reasonable assurance consists of fulfilling a series of steps identified in 10 CFR 50.75(b), (c), (e), and (f). These steps assure that the licensee can certify that financial assurance is in effect for an amount that may be more but not less than the amount stated in the table in 10 CFR 50.75(c)(1). Specifically, this table states that if P equals the thermal power of a reactor in megawatts (MWt), the minimum financial assurance (MFA) funding amount in millions of January 1986 dollars is:

(1) For a PWR: $MFA = (75 + 0.0088P)$

(2) For a BWR: $MFA = (104 + 0.009P)$

For either a PWR or BWR, if the thermal power of the reactor is less than 1200 MWt, then the value of P to be used in 1 and 2 is 1200, and if the thermal power is greater than 3400 MWt, then a value of 3400 is used for P. That is, P is never less than 1200 nor greater than 3400. The financial assurance amounts calculated in equations 1 and 2 are based on January 1986

dollars, in millions. To account for inflation from 1986 to the current year, these amounts must be adjusted annually by multiplying 1 and 2 by an escalation factor (ESC) described in 10 CFR 50.75(c)(2). This ESC is

$$ESC\ (current\ year) = (0.65L + 0.13E + 0.22B)$$

where *L* and *E* are the ESCs from 1986 to the current year for labor and energy, respectively, and are to be taken from regional data of U.S. Department of Labor, Bureau of Labor Statistics, and *B* is an annual ESC from 1986 to the current year for waste burial and is to be taken from the most recent revision of NUREG-1307, "Report on Waste Disposal Charges: Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities." NUREG-1307 is updated from time to time to account for disposal charge changes. In January 1986 (the base year), using disposal costs from DOE's Hanford Reservation waste disposal site, *L*, *E*, and *B* all equaled unity; thus the ESC itself equaled unity. A discussion of the origin of the *0.65L*, *0.13E*, and *0.22B* terms is given in NUREG-1307. Thus,

MFA (in millions, current year dollars) = MFA (in millions, 1986 dollars) x ESC (current year)

NUREG-1307 provides several examples of how to determine the minimum decommissioning fund requirement using the above algorithm.

2. DECOMMISSIONING COST ESTIMATES

The regulations summarized below apply to decommissioning cost estimates:

- 10 CFR 50.75(f)(2) requires that a licensee "...shall at or about 5 years prior to the projected end of operations submit a preliminary decommissioning cost estimate (herein after referred to as the preliminary cost estimate) which includes an up-to-date assessment of the major factors that could affect the cost to decommission." Section 50.75(f)(4) requires a licensee to include plans to adjust funding levels to demonstrate a reasonable level of financial assurance, if necessary, in the preliminary cost estimate.

  In addition, 10 CFR 50.75(c) specifies that the initial certification amount of funds for decommissioning be based on the amounts specified in 10 CFR 50.75(c), which represent the minimum funding level that applicants and licensees must meet. However to meet the 10 CFR 50.75(c) requirements, a power reactor licensee may submit a certification based on a site-specific cost estimate which may be more but not less than the 10 CFR 50.75(b)(1) estimate when a higher funding level is desired than that provided in 10 CFR 50.75(c). The basis for any increases should be provided.

- 10 CFR 50.82(a)(4)(i) requires a licensee to provide an estimate of expected costs for the activities being proposed in the Post-Shutdown Decommissioning Activities Report (PSDAR). The PSDAR is to be submitted prior to or within 2 years following permanent cessation of operations. Regulatory Guide 1.185, "Standard Format and Content for Post-Shutdown Decommissioning Activities Report," identifies the type of information in the PSDAR that would be acceptable to the NRC staff. The cost estimate may be the amount of decommissioning funds estimated to be required

pursuant to 10 CFR 50.75(b) and (c) as currently reported on a calendar-year basis at least once every 2 years to the NRC according to 10 CFR 50.75(f)(1), or a site-specific cost estimate.

- 10 CFR 50.82(a)(8)(iii) requires a licensee to provide a site-specific decommissioning cost estimate within 2 years following permanent cessation of operations. This requirement may be satisfied by including a site-specific estimate as part of the PSDAR. In addition, 10 CFR 50.75(c) specifies that the initial certification amount of funds for decommissioning be based on 10 CFR 50.75(c)(1), which represent the minimum funding level that licensees must meet. The site-specific cost estimate submitted within 2 years following permanent cessation of operations may be significantly higher than the funding level based on the formula. If the site-specific cost estimate results in a funding level that differs from the amount specified in 10 CFR 50.75(c), the licensee must provide the basis for the change.
- 10 CFR 50.82(a)(9)(ii)(F) requires that a licensee provide "an updated site-specific estimate of remaining decommissioning costs..." as part of a License Termination Plan (LTP). According to 10 CFR 50.82(a)(9)(i), the licensee must submit the LTP at least 2 years before termination of the license.

As provided in 10 CFR 50.82(a)(8)(ii), a licensee may at any time without prior notification to the NRC withdraw funds from the decommissioning trust up to a cumulative total of 3 percent of the generic amount calculated under 10 CFR 50.75 for decommissioning planning purposes. After submittal of the certifications of permanent shutdown and fuel removal required under 10 CFR 50.82(a)(1) and commencing 90 days after the NRC has received the PSDAR, the licensee may use an additional 20 percent of the decommissioning funds prescribed in 10 CFR 50.75(c) for decommissioning purposes. The licensee is prohibited from using the remaining 77 percent of the generic decommissioning funds until a site-specific decommissioning cost estimate (SSCE) is submitted to the NRC. In addition, use of decommissioning funds is limited by 10 CFR 50.82(a)(8)(i) to legitimate decommissioning expenses that neither reduce the value of the trust fund below the amount necessary to place and maintain the reactor in a safe storage condition, nor inhibit the licensee's ability to completely fund the trust so that the site is released the license terminated.

3. DECOMMISSIONING COST DEFINITION

As defined in 10 CFR 50.2, "*Decommission* means to remove a facility or site safely from service and reduce residual radioactivity to a level that permits—

(1) Release of the property for unrestricted use and termination of the [Part 50] license; or

(2) Release of the property under restricted conditions and termination of the [Part 50] license."

The decommissioning cost estimates required by the regulations referenced above apply only to those costs that necessary to accomplish the purposes listed in the definition above. Costs that may be incurred by a licensee when it removes a facility from service or restores the site after decontamination is complete but that do not reduce residual radioactivity or are not required to terminate the license are not considered NRC decommissioning costs. Accordingly, they should not be included in the NRC decommissioning cost estimate. A

licensee may choose to report non-NRC decommissioning costs along with its decommissioning cost estimate; however, such costs need to be clearly identified and separated.

4. COST ADJUSTMENT METHODOLOGY

The decommissioning cost estimates based on 10 CFR 50.75(c) for the reference PWR and reference BWR presented in this SRP are based on information developed in NUREG/CR-5884 and NUREG/CR-6174, respectively. All costs presented in this SRP include a 25% contingency factor and are in year 2000 dollars. The cost adjustment methodology described in this section can be used to adjust the costs in this report from year 2000 dollars to any future year. As discussed in Section B.1, costs are divided into three general areas that tend to escalate similarly: (1) labor, materials, and services, (2) energy and waste transportation, and (3) radioactive waste burial/disposition. A typical allocation of cost adjustment factors to the set of reference reactor cost components is presented below in Table 1.

A relatively simple equation can be used to estimate decommissioning costs to account for escalation from the base year 2000 to any other year of interest, year(x). That equation is

$$\textit{Estimated cost [year(x)]} = A_{base}\, L_x + B_{base}\, E_x + C_{base}\, B_x$$

A_{base} = sum of all labor, material, and services cost components

L_x = labor, material, and services adjustment factor, base year 2000 to year(x)

B_{base} = sum of all energy and transportation cost components

E_x = energy and transportation adjustment factor, base year 2000 to year(x)

C_{base} = sum of all radioactive waste burial/disposition costs components, and

B_x = radioactive waste burial/disposition adjustment factor, base year 2000 to year(x)

Table 1. Cost Adjustment Factors Used for Decommissioning Cost Estimates of the Reference PWR[a] and Reference BWR[b]

PWR Cost Component	Adjustment Factor Used	BWR Cost Component	Adjustment Factor Used
Radioactive Component		**Radioactive Component**	
Removal of RPV Internals	L_x	RPV Internals	L_x
Removal of Reactor	L_x	Reactor Pressure Vessel	L_x
Steam Generator Removal	L_x	Sacrificial Shield	L_x
Generator Clading Costs	L_x	Recirculation Pumps	L_x
RCS Piping	L_x	RCS Piping	L_x
Large Miscellaneous RCS	L_x	RCS Piping Insulation	L_x
Small Miscellaneous RCS	L_x	Main Turbine	L_x
Pressurizer	L_x	Main Turbine Condenser	L_x
Pressurizer Relief Tank	L_x	Moisture Separator	L_x
Primary Pumps	L_x	Feed Water Heaters	L_x
Spent Fuel Racks	L_x	Turbine Feed Pumps	L_x
Biological Shield	L_x	Structural Beams, Plates, &	L_x
		Spent Fuel Racks	L_x
Decon. & Dismantlement			
Decon. Buildings	L_x	**Decon. & Dismantlement**	
Removal of Plant Systems	L_x	Decon. of Buildings	L_x
		Removal of Plant Systems	L_x
Management and Support			
Support Staff	L_x	**Management and Support**	
DOC Staff	L_x	Support Staff	L_x
Consultant/Other Staff	L_x	DOC Staff	L_x
Termination Survey Costs	L_x	Consultant/Other Staff	L_x
Regulatory Costs	L_x	Termination Survey Costs	L_x
Special Tools & Equipment	L_x	Regulatory Costs	L_x
Monitoring Costs	L_x	Special Tools and	L_x
Laundry Services	L_x	Environmental Monitoring	L_x
Maintenance Allowance	L_x	Laundry Services	L_x
Small Tools & Equipment	L_x	Maintenance Allowance	L_x
Nuclear Liability Insurance	L_x	Small Tools or Equipment	L_x
Property Taxes	L_x	Nuclear Liability Insurance	L_x
DOC	L_x	Property Taxes	L_x
Steam	L_x	DOC	L_x
Chemical Decon	E_x	Chemical Decontamination	E_x
Plant Power Usage	E_x	Plant Power Usage	E_x
LLW Packaging	L_x	**LLW Packaging**	L_x
LLW Shipping	E_x	**LLW Shipping**	E_x
LLW Burial/Waste Vendor	B_x	**LLW Burial/Waste Vendor**	B_x

[a] NUREG/CR-5884
[b] NUREG/CR-6174

4.1 Labor Adjustment Factors

The adjustment factor for labor, L_x, can be obtained from the "Monthly Labor Review," published by the U.S. Department of Labor, Bureau of Labor Statistics (BLS). Specifically, the appropriate regional data from the table (currently Table 24) entitled "Employment Cost Index, Private Nonfarm Workers, by Bargaining Status, Region, and Area Size," subtitled "Compensation," should be used. These labor adjustment factors can also be obtained from BLS databases made available on the World Wide Web (see NUREG-1307, Appendix C, for instructions). L_x should be adjusted from a base value in Table 24 corresponding to base year 2000, to the year(x) of interest.

To calculate a labor adjustment factor for a particular region, two indices are needed, a value for the base year and a value for the year (x) of interest. These values are shown in Table 2 for each region. The base year 2000 values of L_x from the BLS data are provided in column 2 of Table 2. To adjust the costs to a future year(x), the year (x) values for L_x from the BLS data should be substituted in column 3 (year (x) of interest).

Table 2. Labor Cost Adjustment Factors by Region

Region	Base Year (2000)	Year (x) of Interest
Northeast	144.3	$x_{Northeast}$
South	143.0	x_{South}
Midwest	146.3	$x_{Midwest}$
West	144.7	x_{West}

In general, L_x is calculated for each region by dividing the Year (x) of Interest value (column 3) by the Base Year 2000 value (column 2).

Future labor adjustment factors from BLS should be treated similarly. Future revisions to NUREG-1307 will provide new base year calculations as appropriate. However, if BLS has changed its base year and the change is not reflected in the current revision of NUREG-1307, the licensee should calculate the labor adjustment factor to reflect applicable changes.

4.2 Energy Adjustment Factors

The adjustment factor for energy, E_x, can be obtained from the "Producer Price Indexes," published by the U.S. Department of Labor, Bureau of Labor Statistics (BLS). Specifically, data from the table (currently Table 6) entitled "Producer Price Indexes and Percent Changes for Commodity Groupings and Individual Items" (PPI) should be used.

E_x consists of two components, industrial electric power, P_x, and light fuel oil, F_x. Hence, E_x should be obtained using the BLS data in the following equations:

for the reference PWR: $E_x = [0.58P_x + 0.42F_x]$

for the reference BWR: $E_x = [0.54P_x + 0.46F_x]$

These equations are derived from Table 6.3 of NUREG/CR-0130 and Table 5.3 of NUREG/CR-0672. P_x should be taken from data for industrial electric power (Commodity code 0543), and F_x should be taken from data for light fuel oils (Commodity code 0573). These energy adjustment factors can also be obtained from BLS databases made available on the World Wide Web (see NUREG-1307, Appendix C, for instructions). The Base Year 2000 values for P_x and F_x from BLS data are provided in column 2 of Table 3.

Table 3. Energy Cost Adjustment Factors by Energy Source

	Base Year (2000)	Year (x) of Interest
Industrial electric power	126.5	$x_{electric}$
Light fuel oils	72.9	$x_{fuel\ oil}$

As discussed for L_x in Section 3.1 above, to adjust the costs to a future current year (x), the year (x) values for P_x and F_x should be substituted in column 3. The base year 2000 values of P_x and F_x from the BLS data are 126.5 and 72.9, respectively. No regional BLS data for these PPI commodity codes are currently available. Thus, the values of P_x and F_x for the year (x) of interest are:

$$P_x = (x_{electric})_{Year(x)\ of\ interest} \div (126.5)_{Base\ Year\ 2000}$$

$$F_x = (x_{fuel\ oil})_{Year(x)\ of\ interest} \div (72.9)_{Base\ Year\ 2000}$$

The value of E_x for the reference PWR is therefore

$$E_x = [(0.58P_x) + (0.42F_x)]$$

This value of E_x should then be used in the equation to adjust the energy costs to year(x) dollars for decommissioning a PWR. Correspondingly, the value of E_x for the reference BWR is:

$$E_x = [(0.54P_x) + (0.46F_x)]$$

Future energy adjustment factors from BLS should be treated similarly. Future revisions to NUREG-1307 will provide new base year calculations as appropriate. However, if BLS has changed its base year, and the change is not reflected in the current revision of NUREG-1307, the licensee should calculate the energy adjustment factor to reflect applicable changes.

4.3 Waste Burial Adjustment Factors

The adjustment factor for waste burial/disposition, B_x, can be taken directly from data for the appropriate LLW burial location as given in Table 2.1 of the most recent revision of

NUREG-1307. For example, B_x = 18.129 (in 2000 dollars) for a PWR directly disposing all decommissioning LLW at the South Carolina burial site. The base year 2000 values for B_x are provided in columns 2 and 3 of Table 4.

Table 4. Waste Burial/Disposition Cost Adjustment Factors by Disposition Option and Site

Waste Burial	Base Year (2000)		Year(x) of Interest	
	PWR	BWR	PWR	BWR
Direct Disposal/WA [(a)]	2.223	3.375	$x_{PWR\ Direct\ Disposal/WA}$	$x_{BWR\ Direct\ Disposal/WA}$
Direct Disposal/SC [(b)]	18.129	16.244	$x_{PWR\ Direct\ Disposal/SC}$	$x_{BWR\ Direct\ Disposal/SC}$
Waste Vendor/WA	4.060	4.379	$x_{PWR\ Waste\ Vendor/WA}$	$x_{BWR\ Waste\ Vendor/WA}$
Waste Vendor/SC	8.052	8.189	$x_{PWR\ Waste\ Vendor/SC}$	$x_{BWR\ Waste\ Vendor/SC}$

(a) WA refers to the Washington LLW disposal site located near Richland, Washington.
(b) SC refers to the South Carolina LLW disposal site located near Barnwell, South Carolina.

As discussed for L_x and E_x above, to adjust the costs to a future Year (x), the Year (x) values for B_x from the latest revision of NUREG-1307 should be substituted in columns 4 and 5 of Table 4. For example, to adjust waste disposal costs using the waste vendor option for LLW from a PWR at the South Carolina disposal site from base year 2000 (basis for this SRP) to the waste vendor option at the Washington disposal site in Year (x):

$$B_x = (x_{PWR\ Waste\ Vendor/WA})_{year(x)\ of\ interest} \div (8.052)_{base\ year\ 2000}$$

This value of B_x should then be used in the equation to adjust the waste burial cost to year (x) dollars for LLW waste disposition from a PWR using the waste vendor option with the Washington disposal site.

C. STANDARD REVIEW PLAN FOR DECOMMISSIONING COST ESTIMATES

The purpose of this SRP is to direct the NRC staff's review of the licensee's cost estimates. The major types of cost estimates affecting the licensee are the preliminary cost estimate, the estimate of expected costs presented in the PSDAR, the SSCE required within 2 years following permanent cessation of operations, and the updated SSCE required as part of the LTP. In addition, a licensee may submit a certification amount of funds for decommissioning based on an SSCE that is equal to or greater than that calculated in the formula in 10 CFR 50.75(c)(1) or (2) when a higher funding level is desired. Individual SRPs are provided for the preliminary cost estimate, the estimate of expected costs presented in the PSDAR, the SSCE, and the updated SSCE.

Each SRP is divided into the following sections: (1) Review Responsibilities, (2) Areas of Review, (3) Acceptance Criteria, (4) Review Procedures, (5) Evaluation Findings, and (6) Implementation.

1. PRELIMINARY COST ESTIMATE

The preliminary cost estimate is required at or about 5 years prior to the projected end of operations. The projected end of operations need not be the same as the expiration date of the operating license if a licensee chooses to permanently cease operations at an earlier date. In some cases, a licensee may prematurely shut down and submit its certification of permanent cessation of operations, as required by 10 CFR 50.82(a)(1), more than 5 years prior to the expiration date of the operating license. In this event, the requirement of 10 CFR 50.75(f)(2) to submit a preliminary cost estimate is not applicable. A licensee could choose to submit its preliminary cost estimate as the estimate of expected costs presented in the PSDAR, and thereby satisfy the requirements of 10 CFR 50.82(a)(4)(i).

According to 10 CFR 50.75(f)(4), the licensee is required to include in the preliminary cost estimate plans for adjusting levels of funds for decommissioning, if necessary to demonstrate a reasonable level of assurance that funds will be available when needed to cover the costs of decommissioning. The reviewer should determine whether the licensee must comply with this requirement. If it is required, the reviewer should determine whether the plans provide adequate financial assurance.

By 10 CFR 50.82(a)(8)(iv), licensees who plan to use a period of storage or surveillance (SAFSTOR) are required to provide a means of adjusting cost estimates and associated funding levels over the period of storage or surveillance. If a licensee plans to use a period of SAFSTOR, the reviewer should ensure that the licensee has included a description of its means of adjustment with its preliminary cost estimate. The reviewer should determine if the means described by the licensee provides adequate assurance that funds will be available for decommissioning activities at the time they are needed.

1.1 Review Responsibilities

Primary— Cognizant Project Manager, Project Directorate, Division of Licensing Project Management, Office of Nuclear Reactor Regulation, or as assigned

Secondary— Financial Reviewer, Financial and Regulatory Analysis Section, Reactor Policy and Rulemaking Branch, Division of Regulatory Improvement Programs, Office of Nuclear Reactor Regulation, or as assigned

1.2 Areas of Review

This SRP directs the staff's review of the preliminary cost estimate that 10 CFR 50.75(f)(2) requires to be submitted at or about 5 years before the projected end of operations. The intent of this preliminary estimate is to provide the NRC with an up-to-date estimate of expected costs and identify major factors in the cost of the decommissioning. The licensee will have already submitted a cost estimate for establishing a fund for decommissioning asrequired by 10 CFR 50.75(b). This estimate will have been revised periodically during operation and may be used in preparing the preliminary cost estimate. The preliminary cost estimate will generally be substantially less detailed than the SSCE.

The scope of the review directed by this SRP includes (1) a comparison of the preliminary cost estimate with the minimum decommissioning funding required, and (2) an assessment of the major factors that could affect the preliminary cost estimate.

1.3 Acceptance Criteria

The acceptance criteria are based on the requirements of 10 CFR 50.75(f)(2), 10 CFR 50.75(f)(4), and 10 CFR 50.82(a)(8)(iv), as applicable. The regulations require that each power reactor licensee shall at or about 5 years prior to the projected end of operations submit a preliminary cost estimate which includes an up-to-date assessment of the major factors that could affect the cost to decommission.

- The reviewer should compare the preliminary cost estimate to the minimum decommissioning funding required under 10 CFR 50.75(b) to ensure that the licensee's submittal meets the intent of the regulations given in 10 CFR 50.75.

- The reviewer should ensure that the preliminary cost estimate includes an up-to-date listing of the major factors that could affect the cost to decommission and that these factors are assessed by the licensee.

1.4 Review Procedures

The reviewer will use the following process to determine that the cost estimate has been submitted and that the estimate included an up-to-date assessment of the major factors that could affect the cost to decommission.

1.4.1 Comparison of the preliminary cost estimate to the minimum required decommissioning fund

The reviewer should calculate the minimum decommissioning financial assurance requirement amount derived per the algorithm discussed in Section B.1 of this SRP (10 CFR 50.75(c)) and compare it to the preliminary cost estimate amount. The preliminary cost estimate is acceptable if it is greater than or equal to the decommissioning financial assurance requirement amount. If the preliminary cost estimate is less than the amount derived from the algorithm in 10 CFR 50.75(c), the reviewer shall provide this information to the NRC project manager who will document the finding and inform the licensee in writing of additional information needed to resolve the deficiency.

If the preliminary cost estimate differs from the amount of the generic decommissioning fund amount of 10 CFR 50.75(c), the reviewer should assess the licensee's cost estimate to determine whether all significant costs have been included. The reviewer should assess site-specific conditions identified by the licensee to determine if the site-specific conditions would significantly impact the amount calculated in accordance with 10 CFR 50.75(c).

1.4.2 Assessment of the major factors that could affect the preliminary cost estimate

The following factors should be used by the reviewer to ensure that the cost estimate includes an up-to-date assessment of the major factors that could affect the cost to decommission:

- the decommissioning option/method anticipated to be used
- the potential for known or suspected contamination of the facility or site to affect the cost of decommissioning
- the LLW disposition plan
- the preliminary schedule of decommissioning activities
- any other factors that could significantly affect the cost to decommission

The reviewer should review the preliminary cost estimate to determine if it is sufficiently detailed to allow the reviewer to assess its adequacy. To make this assessment, the reviewer should confirm that the cost estimate is provided in current year (estimate year) dollars and that it accounts for the entire decommissioning work scope. The cost estimate should provide costs for each of the following, or similar, major decommissioning phases:

- Pre-decommissioning engineering and planning—decommissioning engineering and planning prior to completion of reactor defueling
- Reactor deactivation—deactivation and radiological decontamination of plant systems to place the reactor into a safe, permanent shutdown condition
- Safe storage—safe storage monitoring of the facility until dismantlement begins (if storage or monitoring of spent fuel is included in the cost estimate, it should be shown separately)
- Dismantlement—radiological decontamination and dismantlement (D&D) of systems and structures required for license termination (if demolition of uncontaminated structures and site restoration activities are included in the cost estimate, they should be shown separately)
- Low-level radioactive waste (LLW) disposition—LLW packaging, transportation, vendor processing, and disposal. Tables 5 and 6 provide decommissioning cost estimates by these major activities for the NRC reference PWR[1] (NUREG/CR-5884) and reference BWR[2] (NUREG/CR-6174), respectively. The reviewer should compare

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[1] The Portland General Electric Company's Trojan nuclear plant, at Rainier, Oregon, is used as the reference PWR power station. Trojan is an 1175-MW(e) single-reactor power station that utilizes a four-loop pressurized water reactor manufactured by the Westinghouse Electric Corporation in the nuclear steam supply system. Although Trojan was prematurely shutdown on January 4, 1993, the reevaluated decommissioning cost analyses assumed that the Trojan plant operated for the full term of its license to be more representative of large PWRs in general.

[2] The Washington Public Power Supply System's Washington Nuclear Plant Two (WNP-2) at Richland, Washington, is used as the reference BWR power station. WNP-2 is an 1155 MW(e) single-reactor power station that utilizes a nuclear steam supply system with a direct-cycle boiling water reactor

the pliminarycost estimate with the cost values provided in Tables 5 and 6 to make a judgment of the reasonableness of the preliminary cost estimate, recognizing the differences between the reactor for which the preliminary cost estimate was developed and the reference reactors.

If necessary, as required by 10 CFR 50.75(f)(4), the preliminary cost estimate shall also include plans for adjusting levels of funds assured for decommissioning to demonstrate a reasonable level of assurance that funds will be available when needed to cover the cost of decommissioning. However, the evaluation of the reasonable assurance of funding is not conducted as part of the review of the licensee's decommissioning cost estimate. It is conducted according to NUREG-1577. The reviewer should ensure that the appropriate information has been provided.

The reviewer should confirm that the licensee has taken into account any major factors that could affect the cost to decommission. Major factors include the following:

- The decommissioning option/method anticipated to be used. The decommissioning options generally available are DECON, SAFSTOR, or some combination thereof. Section A of this SRP describes each of these options. If the chosen option/method will result in completion of decommissioning more than 60 years after cessation of operations, identification and assessment of the factors causing this delay should be presented. Acceptable factors from 10 CFR 50.82(a)(3) include unavailability of waste disposal capacity and other site-specific factors, such as the presence of other nuclear facilities at the site.

- The potential for known or suspected contamination at the site. Although the requirements described in 10 CFR 50.75(g) for keeping records of spills or other unusual occurrences are outside the scope of this SRP, the reviewer should ensure that the licensee has evaluated the anticipated extent of contamination on the facility and site based on information available in the decommissioning files. This description need not be a detailed discussion but should include descriptions of known instances of releases of contaminated materials into the facility and the external environment, and the possible impact on decommissioning. Known environmental contamination should be identified (including soil, groundwater, surface water, etc.). (Note, the files required to be kept, pursuant to 10 CFR 50.75(g), include records of spills or other unusual occurrences involving the spread of contamination in and around the facility, equipment, or site; as-built drawings and modifications of structures and equipment in restricted areas where radioactive materials are used and/or stored and of locations of possible inaccessible contamination such as buried pipes which may be subject to contamination; records of the cost estimates performed for the decommissioning funding plan or of the amount certified for decommissioning; and records of the funding method used for assuring funds if either a funding plan or certification is used.)

- A brief description of the plans for LLW disposal. The reviewer should determine if the licensee specifically evaluated the plans for LLW management, including the anticipated LLW disposal situation, and how LLW will be managed if no LLW disposal

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manufactured by the General Electric Company. WNP-2 has a Mark II containment. The reevaluated decommissioning cost analyses assumed that the WNP-2 plant operated for the full term of its license.

sites are available. The reviewer should understand the site-specific factors that could impact the disposition of spent fuel and LLW to determine the reasonableness of these plans.

- A preliminary schedule that shows the major decommissioning activities and the time period over which each of these activities extend. Typical major decommissioning activities were described above.

- Any other major site-specific factors that could have a significant effect on the cost of decommissioning, such as large volumes of mixed radioactive-hazardous wastes with uncertain disposition pathways and known regulatory or technical issues having uncertain resolution outcomes.

1.5 Evaluation Findings

Using the acceptance criteria in C.1(3) and the review procedure in C.1(4) of this section as a basis, the NRC reviewer shall verify that sufficient information has been provided to satisfy the requirements of the underlying regulations (10 CFR 50.75(f)(2)). The preliminary cost estimate shall be considered deficient if the decommissioning cost estimate is less than the financial assurance amount required by 10 CFR 50.75(c), or if the assessment of the major factors that could affect the preliminary cost estimate are not adequate, or if site-specific factors invalidate the technical basis of the formula used to calculate the minimum fund amount in 10 CFR 50.75(c). If deficiencies are discovered, the reviewer should request the appropriate information from the licensee in writing. The reviewer documents the findings of his/her review of the preliminary cost estimate and places a copy of the memorandum into the licensee's docket.

If the licensee included plans to adjust the level of funds assured for decommissioning in accordance with 10 CFR 50.75(f)(4) and 10 CFR 50.82(a)(8)(iv), the reviewer should document the plans to adjust the level of funding.

1.6 Implementation

The method described in this SRP will be used by the staff in evaluating conformance with the Commission's regulations, except when the licensee proposes an acceptable alternative for complying with specified portions of the regulations.

2. ESTIMATE OF EXPECTED COSTS IN THE PSDAR

Prior to or within 2 years following permanent cessation of operations, the licensee is required by 10 CFR 50.82(a)(4)(i) to submit a PSDAR to the NRC. In addition to other prescribed content, this report is required to include an estimate of expected costs. Regulatory Guide 1.185 identifies the type of information to be contained in the PSDAR that would be acceptable to the NRC staff. The cost estimate may be the amount of decommissioning funds estimated to be required by 10 CFR 50.75(b) and (c) as currently reported on a calendar-year basis at least once every 2 years to the NRC according to 10 CFR 50.75(f)(1), or it may be a site-specific cost estimate. Other related but non-NRC decommissioning costs (spent fuel storage, site restoration, etc.) may be included in the cost estimate if desired; however, the cost of decommissioning, as defined by 10 CFR 50.2, should be listed separately. As a separate item, the cost of placing and maintaining the

facility in safe storage should be identified, along with a plan to ensure that sufficient funds will be available for this purpose, if necessary, until such time as the radioactively contaminated material is placed in an authorized waste disposal site. The reviewer should note that, as with the PSDAR, 10 CFR 50.82(a)(8)(iii) requires a licensee to provide a SSCE within 2 years following permanent cessation of operations. If the cost estimate provided with the PSDAR was an SSCE, then this requirement has been satisfied.

Licensees who plan to use a period of storage or surveillance (SAFSTOR) are required by 10 CFR 50.82(a)(8)(iv) to provide a means of adjusting cost estimates and associated funding levels over the period of storage or surveillance. If a licensee intends to use a period of SAFSTOR, the reviewer should ensure that the licensee has included a description of its means of adjustment with its estimate of expected costs. The reviewer should determine whether the means described by the licensee provides adequate assurance that funds will be available for decommissioning activities at the time they are needed.

Table 5. Decommissioning Cost Distribution by Time Period—Reference PWR [a]

Decommissioning Option		Decommissioning Cost (2000 $millions)[b]				
		Period 1 Planning & Preparation	Period 2 Plant Deactivation	Period 3 Safe Storage Operations	Period 4 Dismantlement	Total
DECON						
	Period Years	2.5	0.6	6.3	1.7	11.1
	Period Cost	14.3	56.9	10.8	151.7	233.7
SAFSTOR						
	Period Years	2.5	0.6	57.7	1.7	62.5
	Period Cost	14.3	56.9	144.3	148.5	364.0

[a] NUREG/CR-5884 (Ref. 5)
[b] Includes an assumed 25% contingency cost. SAFSTOR2 decommissioning option is assumed.

A. Cost Estimate Using Minimum Financial Assurance Funding Amount Method

(1) Review Responsibilities

Primary—Cognizant Project Manager, Project Directorate responsible for the reactor, Division of Licensing Project Management, Office of Nuclear Reactor Regulation, as assigned.

Secondary—Financial Reviewer, Financial and Regulatory Analysis Section, Reactor Policy and Rulemaking Branch, Division of Regulatory Improvement Programs, Office of Nuclear Reactor Regulation, or as assigned.

Table 6. Decommissioning Cost Distribution by Time Period -- Reference BWR [a]

Decommissioning Option	Decommissioning Cost (2000 $ millions) [b]				
	Period 1 Planning & Preparation	Period 2 Plant Deactivation	Period 3 Safe Storage Operations	Period 4 Dismantle-ment	Total
DECON					
Period Years	2.5	1.2	3.4	1.7	8.8
Period Cost	14.8	76.1	7.2	243.2	341.3
SAFSTOR					
Period Years	2.5	1.2	57.1	1.7	62.5
Period Cost	14.8	76.1	189.2	242.0	522.1

[a] NUREG/CR-6174 (Ref. 6)
[b] Includes an assumed 25% contingency cost. SAFSTOR2 decommissioning option is assumed.

(2) Areas of Review

This SRP directs the staff's review of the cost estimate that is required by 10 CFR 50.82(a)(4)(i) to be included in the PSDAR submitted prior to or within 2 years following permanent cessation of operations. The intent of this estimate of expected costs is to provide the NRC with an up-to-date cost estimate using the minium financial assurance funding amount method (10 CFR 50.75(c), the same method the licensee used in the submittal for establishing a fund for decommissioning as required by 10 CFR 50.75(b). This estimate will have been revised periodically during operation and may have been used in preparing the preliminary cost estimate.

(3) Acceptance Criteria

The acceptance criteria are based on regulations set out in 10 CFR 50.82(a)(4)(i). The regulations require that, within 2 years following permanent cessation of operations, the licensee shall submit a PSDAR to the NRC with a copy to the affected State or States. The report must include, among other things, an estimate of expected costs.

The acceptance criterion for the cost estimate is that the estimate at least equals the minimum financial assurance funding amount defined in 10 CFR 50.75(c) unless otherwise adequately justified. Only those costs contained in the description of decommissioning, as defined in 10 CFR 50.2, may be used to determine if the estimate at least equals the minimum funding requirement of 10 CFR 50.75(c). Therefore, the estimate should separate costs into categories that enable the reviewer to identify whether or not each listed item fits within the definition of decommissioning costs.

(4) Review Procedures

The reviewer will use the following process to determine that the submitted estimate of expected costs considers, in adequate detail, all major factors that could affect the cost to decommission.

The reviewer should verify that the procedure for calculating the MFA funding amount has been followed in determining the estimate of expected costs (see Section B.1). The reviewer should confirm that the cost estimate is provided in current year (estimate year) dollars, using disposal cost adjustment factors from the most recent revision of NUREG-1307, and that the factors affecting the funding algorithm calculation are verifiable.

The reviewer should confirm that the following information is provided and that all items are reasonable:

- Reactor thermal power rating
- Reactor type (PWR/BWR)
- Cost escalation factors (including an acceptable method of inflation adjustment; Section B.1 provides an acceptable method of allowing for escalation of costs due to inflation in unit costs of labor, energy (transportation), and waste burial).

(5) Evaluation Findings

Using the acceptance criteria in C.2.A(3) and the review procedure in C.2.A(4) of this section as a basis, the NRC reviewer shall verify that sufficient information has been provided to satisfy the requirements of the (10 CFR 50.82(a)(4)(i)). The estimate of expected costs shall be considered deficient if the decommissioning cost estimate is less than the financial assurance amount required by 10 CFR 50.75(c) and adequate justification is not provided. If deficiencies are discovered, the reviewer should provide this information to the NRC project manager for the plant. The NRC project manager will inform the licensee in writing of the deficiencies that must be corrected before major decommissioning activities can begin. The reviewer documents the findings of his/her review of the estimate of expected costs in a memorandum. The memorandum should be forwarded for inclusion in the review of the licensee's PSDAR.

(6) Implementation

The method described in this SRP will be used by the staff in evaluating conformance with the Commission's regulations, except when the licensee proposes an acceptable alternative for complying with specified portions of the regulations.

Table 7. Estimate of Expected Costs—PWR DECON [a]

Decommissioning Activity	Decommissioning Cost (2000 $millions) [b]				
	Period 1 (2.5 Years)	Period 2 (0.6 Years)	Period 3 (6.3 Years)	Period 4 (1.7 Years)	Duration (11.1 Years)
	Planning & Preparation	Plant Deactivation	Safe Storage Operations	Dismantlement	Total Cost
Radioactive Component Removal	0.0	0.7	0.0	11.8	12.5
Decontamination and Dismantlement	0.0	22.5	0.0	10.4	32.9
Management and Support	14.3	14.7	10.8	40.5	80.2
LLW Packaging	0.0	0.2	0.0	3.5	3.6
LLW Shipping	0.0	1.5	0.0	4.3	5.8
LLW Burial/Waste Vendor	0.0	17.3	0.0	81.3	98.5
Total Cost	14.3	56.9	10.8	151.7	233.6

[a] NUREG/CR-5884
[b] Assumes a 25% contingency cost.

Table 8. Estimate of Expected Costs—BWR DECON [a]

Decommissioning Activity	Decommissioning Cost (2000 $millions) [b]				
	Period 1 (2.5 Years)	Period 2 (1.2 Years)	Period 3 (3.4 Years)	Period 4 (1.7 Years)	Duration (8.8 Years)
	Planning & Preparation	Plant Deactivation	Safe Storage Operations	Dismantlement	Total Cost
Radioactive Component Removal	0.0	1.2	0.0	6.6	7.8
Decontamination and Dismantlement	0.0	20.8	0.0	15.8	36.6
Management and Support	14.8	34.7	7.2	40.0	96.8
LLW Packaging	0.0	0.2	0.0	5.5	5.7
LLW Shipping	0.0	1.1	0.0	0.4	1.5
LLW Burial/Waste Vendor	0.0	18.1	0.0	174.8	192.8
Total Cost	14.8	76.1	7.2	243.2	341.3

[a] NUREG/CR-6174
[b] Assumes a 25% contingency cost.

Table 9. Estimate of Expected Costs—PWR SAFSTOR [a]

Decommissioning Activity	Decommissioning Cost (2000 $millions) [b]				
	Period 1 (2.5 Years)	Period 2 (0.6 Years)	Period 3 (57.7 Years)	Period 4 (1.7 Years)	Duration (62.5 Years)
	Planning & Preparation	Plant Deactivation	Safe Storage Operations	Dismantle-ment	Total Cost
Radioactive Component Removal	0.0	0.7	0.0	11.8	12.5
Decontamination and Dismantlement	0.0	22.5	1.2	9.2	32.9
Management and Support	14.3	14.7	142.5	40.4	212.0
LLW Packaging	0.0	0.2	0.1	3.4	3.6
LLW Shipping	0.0	1.5	0.0	4.3	5.8
LLW Burial/Waste Vendor	0.0	17.3	0.4	79.4	97.0
Total Cost	14.3	56.9	144.3	148.5	363.9

[a] NUREG/CR-5884
[b] Assumes a 25% contingency cost. SAFSTOR2 decommissioning option is assumed.

Table 10. Estimate of Expected Costs—BWR SAFSTOR [a]

Decommissioning Activity	Decommissioning Cost (2000 $millions) [b]				
	Period 1 (2.5 Years)	Period 2 (1.2 Years)	Period 3 (57.1 Years)	Period 4 (1.7 Years)	Duration (62.5 Years)
	Planning & Preparation	Plant Deactivation	Safe Storage Operations	Dismantle-ment	Total Cost
Radioactive Component Removal	0.0	1.2	0.0	6.6	7.8
Decontamination and Dismantlement	0.0	20.8	0.7	15.1	36.6
Management and Support	14.8	34.7	188.2	41.6	279.3
LLW Packaging	0.0	0.2	0.0	5.5	5.7
LLW Shipping	0.0	1.1	0.0	0.4	1.5
LLW Burial/Waste Vendor	0.0	18.1	0.3	172.8	191.1
Total Cost	14.8	76.1	189.2	242.0	522.1

[a] NUREG/CR-6174
[b] Assumes a 25% contingency cost. SAFSTOR2 decommissioning option is assumed.

B. Site-Specific Cost Estimate

The estimate of expected decommissioning costs required for the PSDAR can be the same as the site-specific cost estimate required by 10 CFR 50.82(a)(8)(iii). The site-specific cost estimate is a detailed assessment that incorporates the cost impact of site-specific factors. The site-specific estimate is discussed in Regulatory Position 3.

A site-specific cost estimate is required by 10 CFR 50.82(a)(8)(iii) to be submitted within 2 years following permanent cessation of operations. This cost estimate may be included with the PSDAR (10 CFR 50.82(a)(4)(i)). In addition, a licensee may submit a certification amount of funds for decommissioning based on a site-specific cost estimate that is equal to or greater than the amount calculated in the formula in 10 CFR 50.75(c)(1) or (2) when a higher funding level is desired. If the amount of the site-specific cost estimate is less than the certification formula amount, a licensee must provide adequate justification for the difference.

The SSCE is a very detailed assessment that incorporates the cost impact of site-specific factors. Because the SSCE that may be submitted with the PSDAR can be used to satisfy the requirement for a SSCE in 10 CFR 50.82(a)(8)(iii), the same review process should be used. The reviewer is referred to the Acceptance Criteria and Review Procedures that are provided in Section 3.

3. SITE-SPECIFIC COST ESTIMATE

A SSCE is required by 10 CFR 50.82(a)(8)(iii) within 2 years following permanent cessation of operations. It may be included with the PSDAR (10 CFR 50.82(a)(4)(i)). The SSCE is intended to be based on a detailed analysis of the decommissioning costs required to safely dismantle and decontaminate the facility and site to meet the criteria for license termination. The SSCE submitted to the NRC may summarize the results of the detailed analyses with the underlying detail submitted as supplementary information. The summary data should be sufficiently detailed to demonstrate that the licensee has considered all significant decommissioning costs, and should reference the detailed cost estimate.

Licensees who plan to use a period of storage or surveillance (SAFSTOR) are required by 10 CFR 50.82(a)(8)(iv) to provide a means of adjusting cost estimates and associated funding levels over the period of storage or surveillance. If the time period covered by the updated SSCE includes a period of SAFSTOR, the reviewer should ensure that the licensee has included a description of its means of adjusting its SSCE. The reviewer should determine if the means described by the licensee provides adequate assurance that funds will be available for decommissioning activities at the time needed.

(1) Review Responsibilities

Primary—Cognizant Project Manager, Project Directorate, Division of Licensing Project Management, Office of Nuclear Reactor Regulation, or Office of Nuclear Materials Safety and Safeguards depending on when submitted.

Secondary—Financial Reviewer, Financial and Regulatory Analysis Section, Reactor Policy and Rulemaking Branch, Division of Regulatory Improvement Programs, Office of Nuclear Reactor Regulation, or Office of Nuclear Material Safety and Safeguards.

(2) Areas of Review

This SRP directs the staff's review of the SSCE that is required by 10 CFR 50.82(a)(8)(iii) within 2 years following permanent cessation of operations. The intent of this cost estimate is to provide the NRC with a detailed assessment that incorporates the cost impact of site-specific factors. Additionally, site-specific estimates may be submitted pursuant to 10 CFR 50.75(b) provided they are equal to or greater than the amount required by 10 CFR 50.75(c).

(3) Acceptance Criteria

The acceptance criteria are based on regulations set out in 10 CFR 50.82(a)(8)(iii). The regulations require that within 2 years following permanent cessation of operations, if the licensee has not already submitted a SSCE with the PSDAR (10 CFR 50.82(a)(4)(i)).

To ensure that the cost estimate is site-specific and that all significant decommissioning costs have been considered, a SSCE should include the following items:

- A description of the decommissioning cost estimating methodology
- A description of the overall decommissioning project
- A summary decommissioning cost estimate by major activity and phase
- A schedule of the major decommissioning activities
- A summary of the radiological D&D management with support staff levels
- An estimate of the radioactive waste volume

(4) Review Procedures

The reviewer will use the following process to determine that the submitted SSCE considers, in adequate detail, all major site-specific factors that could affect the cost to decommission, and to ensure that the SSCE appears reasonable.

The reviewer should compare the SSCE with the minimum decommissioning financial assurance requirement amount derived per the algorithm discussed in Section B.1 (10 CFR 50.75(c)). If the SSCE is less than the amount derived from the algorithm in 10 CFR 50.75(c) and adequate justification is not provided, the reviewer should provide this information to the NRC project manager for the plant. As discussed, the NRC project manager will inform the licensee in writing of additional information needed to resolve the deficiency.

The reviewer should first review the SSCE to determine if it is sufficiently detailed to allow the reviewer to make an assessment of its adequacy. If the reviewer is unable to find each of the detailed items, then the reviewer will need to make a determination as to whether enough information has been provided to evaluate each of the six items discussed under

Acceptance Criteria (above). If there is not sufficient information, the NRC reviewer will inform project manager, who will inform the licensee in writing of the additional information needed to resolve the deficiency.

1. The reviewer should confirm that the following information is provided:

a. A description of the decommissioning cost estimating methodology

The reviewer should check for the following items to ensure that the licensee's description of the decommissioning cost methodology is complete.

- The decommissioning option/method—The reviewer should identify the decommissioning option/method that the licensee is planning to use. The decommissioning options generally available are DECON, SAFSTOR, or some combination thereof. Section A of this SRP describes each of these options. If the chosen option/method will result in completion of decommissioning more than 60 years after cessation of operations, identification and assessment of the factors causing this delay should be presented. Acceptable factors from 10 CFR 50.82(a)(3) include unavailability of waste disposal capacity and site-specific factors, such as the presence of other nuclear facilities at the site.

- A discussion of the methodology used to derive the cost estimates—The reviewer should identify the methodology used to develop the generic cost estimate. The most common methodology used to develop decommissioning cost estimates is the unit cost factor approach, which is the methodology utilized in the NRC reports mentioned above and the methodology developed by the Atomic Industrial Forum (now the Nuclear Energy Institute) for use by nuclear power plant licensees (AIF/NESP-036). Other methodologies, such as activity-based cost estimates, are acceptable.

b. A description of the overall decommissioning project

The reviewer should check to ensure that the licensee has provided a detailed work breakdown for all the activities to be performed, including planning and preparation. The reviewer should specifically check that the following activities have been included:

- Planning and preparation
- Characterization survey of facility and site
- Disposal of ionexchanger resins
- Removal, radiological decontamination, and packaging of spent fuel racks
- Concentration and shipment of boron waste
- Radiological decontamination of systems using chemical cleaning methods
- Draining and processing of spent fuel pool water
- Removal of spent fuel pool cooling system
- Removal and packaging of reactor pressure vessel (RPV) internals

- Radiological decontamination and closure of RPV
- Removal of contaminated cranes
- Radiological decontamination, removal, and packaging of spent fuel pool liner
- Removal of reactor coolant system (RCS) piping and equipment
- Removal of pressurizer
- Removal of steam generators
- Removal of control rod drive system
- Segmentation and packaging of reactor pressure vessel
- Removal of bioshield shield
- Removal of turbine generator(s)
- Removal of turbine condenser(s)
- Removal of moisture separator reheaters
- Removal of feedwater heaters
- Removal of feedwater condensate system
- Removal of feedwater pumps/turbine drives
- Radiological decontamination and removal of floor drains
- Vacuuming or washing or other radiological decontamination of surfaces
- Removal of contaminated concrete
- Removal of heating, ventilation, and air conditioning ducts and equipment
- Removal of other contaminated systems (list each system)
- Remediation/removal of surface and groundwater
- Remediation/removal of contaminated soils
- Final survey
- LLW packaging, shipping, and burial charges, including LLW processing fees by waste vendors
- Shipment and processing or storage of greater-than-Class C waste

If the decommissioning project includes SAFSTOR periods (longer than about 5 years), the reviewer should also check that the schedule includes the following activities and labor requirements were included:

- Removal of any LLW that is ready to be shipped
- Deenergizing or deactivating specific systems
- Reconfiguration of ventilation systems and fire protection systems for use during the storage period
- Maintenance of any systems critical to final dismantlement during the storage period

- Mobilization of additional personnel at the end of the SAFSTOR period to begin the active phase of decommissioning work

The reviewer should also check for the following information:

- A summary of the inventory of contaminated systems and components requiring radiological decontamination and/or decommissioning (Table 11 provides an example of a contaminated equipment and piping inventory for the reference PWR and reference BWR (see NUREG/CR-5584 and NUREG/CR-6174)). The reviewer should compare the inventory provided with Table 11 in order to make a judgment regarding the reasonableness of the inventory.

Table 11. Example of Inventory for Contaminated Equipment and Piping

Equipment Category[a]	Reference PWR Length of Piping in Feet or Number of Items in Each Category	Reference BWR Length of Piping in Feet or Number of Items in Each Category
Piping diameter > 3 inches	15,110	55,654
Piping diameter ≤ 3 inches	34,631	66,160
Valves > 3 inches	235	1,103
Valves ≤ 3 inches	779	7,962
Tanks of all sizes	76	80
Pumps > 100 pounds	43	87
Pumps ≤ 100 pounds	2	8
Heat exchangers > 100 pounds	25	16
Heat exchangers ≤ 100 pounds	0	0
Electrical components > 100 pounds	69	0
Electrical components ≤ 100 pounds	34	0
Miscellaneous components > 100 pounds	13	1,323
Miscellaneous components ≤ 100 pounds	26	282
Large piping hanger, for pipes > 4 inches in diameter	2,204	5,000
Small piping hanger, for pipes ≤ 4 inches in diameter	10,608	7,500

[a] The equipment categories shown here are arbitrary. Any reasonable method of categorization is acceptable.

- An identification of the rooms and/or areas in the facility that need to be decontaminated (this information may have been either submitted by the licensee either as maps or provided in tables). Table 12 provides a table example of an inventory of concrete and metal surfaces requiring radiological decontamination/removal for the reference PWR and reference BWR. The reviewer should compare the inventory provided with Table 12 in order to make a judgment regarding the reasonableness of the inventory.

Table 12. Example of Inventory for Concrete and Metal Surfaces Requiring Decontamination/Removal

Reference PWR (DECON and SAFSTOR)				
Building or Location	**Area of Concrete Decontaminated (ft^2)**	**Volume of Concrete Removed (ft^3)**	**Area of Metal Surfaces Decontaminated (ft^2)**	**Volume of Metal Surfaces Removed (ft^3)**
Fuel Building	22,864	548	15,428	161
Containment Building	127,124	433	4,690	49
Auxiliary Building	43,860	819	0	0
Reference BWR (DECON and SAFSTOR)				
Building or Location	**Area of Concrete Decontaminated (ft^2)**	**Volume of Concrete Removed (ft^3)**	**Area of Metal Surfaces Decontaminated (ft^2)**	**Volume of Metal Surfaces Removed (ft^3)**
Reactor	30,537	1,304	33,906	541
Rad Waste/Control Building	21,711	388	1,526	16
Turbine Generator Building	8,042	123	1,526	16

- A summary description, based on the decommissioning records required by 10 CFR 50.75(g), of events occurring during operation involving the spread of contamination in and around the facility, equipment, or site, such that significant contamination remained after any cleanup procedures were carried out. Records of events that may have spread contamination into inaccessible areas or resulted in possible seepage into porous materials must be maintained. The decommissioning records must include as-built drawings and modifications to structures and equipment in restricted areas where radioactive materials were used or stored, and the locations of areas of possible inaccessible contamination, such as buried pipes. These records are intended to provide a historical record of the location, use, and spread of radioactive materials that can be used to guide decommissioning efforts.

Although the requirements described in 10 CFR 50.75(g) for keeping records of spills or other unusual occurrences are outside the scope of this SRP, the reviewer should ensure that the licensee has evaluated the anticipated extent of contamination on the facility and site based on information available in the decommissioning files. This description need not be a detailed discussion but should describe known instances of releases of contaminated materials into the facility and the external environment, as well as the possible impact on decommissioning. The licensee's discussion should include an evaluation of the historical use and location of radioactive materials at the site with an assessment of their impact on decommissioning costs.

The record-keeping requirements of 10 CFR 50.75(g) became effective on July 27, 1988. As a result, events that occurred before the effective date may not be included in the licensee's decommissioning records. Therefore, for plants with operating histories prior to July 1988, the reviewer should determine whether the licensee evaluated the plant's operating history and the modifications made to its facility, equipment, and site to assess their impact on decommissioning costs.

- A summary of available characterization information on known and/or suspected environmental contamination (soil, groundwater, and surface water). The reviewer should look for the identification of known environmental contamination (including soil, groundwater, surface water, etc.). The files that are required by 10 CFR 50.75(g) include records of spills or other unusual occurrences involving the spread of contamination in and around the facility, equipment, or site; as-built drawings and modifications of structures and equipment in restricted areas where radioactive materials are used and/or stored; locations of possible inaccessible contamination such as buried pipes.
- Records of the cost estimates performed for the decommissioning funding plan or the amount certified for decommissioning; and records of the funding method used for assuring funds if either a funding plan or certification is used.
- A summary description of structures or equipment in the restricted area where radioactive materials were used or stored, as well as the locations of possible inaccessible contamination.

c. A summary decommissioning cost estimate by major activity and phase

- The reviewer should confirm that the cost estimate accounts for the entire decommissioning work scope, but not for items that are outside the scope of the decommissioning process such as the maintenance and storage of spent fuel in the spent fuel pool, the design or construction of spent fuel dry storage facilities, or other activities not directly related to the long-term storage, radiological D&D of the facility, or radiological decontamination of the site. If non-decommissioning cost items are included in the SSCE, these items should be identified separately. The SSCE should provide costs for each of the following, or similar, major activities and phases:

  - Major radioactive component removal—reactor vessel and internals, steam generators, pressurizers, large bore reactor coolant system piping, and other large components that are radioactive to a comparable degree, as defined in 10 CFR 50.2
  - Radiological D&D—removal of remaining radioactive plant systems, including radiological decontamination
  - Management and support—labor costs of support staff and decommissioning contractor's staff, energy costs, regulatory costs, small tools, insurance, etc.
  - LLW packaging—placing LLW in packages
  - LLW shipping—shipping LLW to waste vendors/burial site

- LLW burial/waste vendor—LLW burial charges, including LLW processing fees by waste vendors

- Contingency

If the SAFSTOR option is being used, the cost categories should also be segregated into the following:

- Pre-decommissioning engineering and planning/plant deactivation— all activities from engineering and planning through defueling and layup to completing the placement of the reactor into permanent shutdown condition

- Extended safe storage operations—safe storage monitoring of the facility until dismantlement begins (if storage or monitoring of spent fuel is included in the cost estimate, it should be shown separately)

- Final Radiological D&D—radiological D&D of radioactive systems and structures required for license termination, including demolition for the purposes of reducing residual radioactivity if demolition of uncontaminated structures and site restoration activities are included in the cost estimate, they should be shown separately

Tables 7 through 10 provide decommissioning cost estimates by decommissioning activities listed in Section3(4)1c and time periods for the NRC reference PWR and reference BWR (see NUREG/CR-5884 and NUREG/CR-6174), respectively. The reviewer should compare the SSCE with the cost values provided in Tables 7 through 10 to make a judgment of the reasonableness of the SSCE, recognizing the difference between the reactor for which the SSCE was developed and the reference reactors.

- An estimate of the cost necessary to place and maintain the reactor in a safe storage condition if such action becomes necessary
- A description of how the contingency costs are calculated
- A description of how inflation is accounted for in the cost estimate—The reviewer should confirm that the cost estimate is provided in current year (estimate year) dollars and that escalation of the LLW disposition costs is considered separately from the general inflation rate applicable to labor, material, and energy costs. The reviewer should be aware of escalation rates used in the current revision of NUREG-1307.
- A schedule showing the amount of decommissioning funds currently available, the accumulation of additional funds, and the expenditure of the decommissioning funds
- The assumptions, references, and bases for unit costs that were used in developing the estimates

d. A schedule of decommissioning activities

The reviewer should check to ensure that the schedule includes a work breakdown decommissioning activities (as discussed previously), periods of interim safe storage, labor requirements (person-hours), and key milestones.

e. Radiological D&D management— Support and DOC staffing levels

The reviewer should check to ensure that the licensee has estimated staffing levels, labor requirements, and labor costs for each decommissioning phase (including periods of SAFSTOR, if applicable). Radiological D&D staff requirements may vary from site to site, depending on management. For this reason, the reviewer should determine if labor rates were adjusted for escalation and region accordingly.

f. Radioactive waste information

The reviewer should determine if the licensee submitted estimates of radioactive waste volumes that are expected to be generated during decommissioning, assuming no volume reduction. Radioactive waste (radwaste) volumes should be identified by waste class. In addition, the reviewer should identify if the licensee submitted plans for radwaste disposition, including radwaste disposal sites to be used, if available. If the licensee has specified that a vendor will process the waste, then the radwaste information after processing should be available to show the results of the waste minimization. The licensee may also have included descriptions of the methods and technologies employed to achieve the improved waste characteristics.

2. The reviewer should assess the reasonableness of submitted SSCEs and compare the information that was submitted with the information that is provided in this section for the reference PWR and BWR using the following process.

a) The reviewer should compare the information presented in this section for the referenced PWR or BWR with the level of detail provided in the SSCE. The reviewer should check to see if there are items that appear to be significantly less than the amounts given in the following tables (taking into account the differences in plant sizes or decommissioning techniques) or that are significantly out of proportion. If the numbers are significantly different or out of proportion, before determining that the SSCE is deficient, the reviewer should check for an explanation or reason that might account for the difference.

b) The reviewer should compare the cost estimates with detailed analyses as the reevaluated analyses of decommissioning of the NRC reference PWR and the reference BWR (see NUREG/CR-5884 and NUREG/CR-6174). Summaries of reports to be used for this comparison are presented below for a PWR undergoing the immediate dismantlement option (DECON) in Table 13 and for the safe storage option (SAFSTOR) in Table 14. Likewise for a BWR, Table 15 summarizes the DECON option and Table 16 summarizes the SAFSTOR option.

Table 13. Reference PWR Decommissioning Cost Distribution by Time Period— DECON

Decommissioning Activity	Decommissioning Cost (2000 $ thousands) Period 1 (2.5 Years) Planning & Preparation	Period 2 (0.6 Years) Plant Deactivation	Period 3 (6.3 Years) Safe Storage Operations	Period 4 (1.7 Years) Dismantlement	Duration (11.1 Years) Total Cost
Radioactive Component Removal					
Removal of RPV Internals	0	743	0	0	743
Removal of Reactor Pressure Vessel	0	0	0	254	254
Steam Generator Direct Removal Costs	0	0	0	9,789	9,789
Steam Generator Cascading Costs	0	0	0	223	223
RCS Piping	0	0	0	35	35
Large Miscellaneous RCS Piping	0	0	0	36	36
Small Miscellaneous RCS Piping	0	0	0	67	67
RCS Insulation	0	0	0	0	0
Pressurizer	0	0	0	13	13
Pressurizer Relief Tank	0	0	0	9	9
Primary Pumps	0	0	0	51	51
Spent Fuel Racks	0	0	0	1,038	1,038
Biological Shield	0	0	0	272	272
Subtotal	0	743	0	11,787	12,530
Decontamination and Dismantlement					
Decontamination of Site Buildings	0	22,487	0	2,002	24,490
Removal of Contaminated Plant Systems	0	0	0	8,418	8,418
Subtotal	0	22,487	0	10,420	32,908
Management and Support					
Support Staff	942	9,433	2,992	5,323	18,689
DOC Staff	7,579	0	1,516	18,737	27,832
Consultants/Other Staff	0	0	0	190	190
Termination Survey Costs	0	0	0	1,916	1,916
Regulatory Costs	561	582	35	1,608	2,787
Special Tools and Equipment	5,216	0	0	0	5,216
Environmental Monitoring Costs	0	47	48	130	225
Laundry Services	0	496	92	1,456	2,044
Small Tools and Minor Equipment	0	15	0	411	426
Nuclear Liability Insurance	0	2,695	5,934	3,199	11,827
Property Taxes	0	0	89	240	329
DOC Mobilization/Demobilization Costs	0	0	0	4,144	4,144
Steam Generator Undistributed Costs	0	0	0	328	328
Chemical Decon	0	414	0	0	414
Plant Power Usage	0	1,011	59	2,771	3,840
Subtotal	14,298	14,693	10,764	40,453	80,208
LLW Packaging	0	167	0	3,464	3,631
LLW Shipping	0	1,518	0	4,323	5,841
LLW Burial/Waste Vendor	0	17,251	0	81,264	98,515
Total	14,298	56,859	10,764	151,712	233,632

Table 14. Reference PWR Decommissioning Cost Distribution by Time Period— SAFSTOR

Decommissioning Activity	Decommissioning Cost (2000 $thousands)				
	Period 1 (2.5 Years) Planning & Preparation	Period 2 (0.6 Years) Plant Deactivation	Period 3 (57.7 Years) Safe Storage Operations	Period 4 (1.7 Years) Dismantle-ment	Duration (62.5 Years) Total Cost
Radioactive Component Removal					
Removal of RPV Internals	0	743	0	0	743
Removal of Reactor Pressure Vessel	0	0	0	254	254
Steam Generator Direct Removal Costs	0	0	0	9,789	9,789
Steam Generator Cascading Costs	0	0	0	223	223
RCS Piping	0	0	0	35	35
Large Miscellaneous RCS Piping	0	0	0	36	36
Small Miscellaneous RCS Piping	0	0	0	67	67
RCS Insulation	0	0	0	0	0
Pressurizer	0	0	0	13	13
Pressurizer Relief Tank	0	0	0	9	9
Primary Pumps	0	0	0	51	51
Spent Fuel Racks	0	0	0	1,038	1,038
Biological Shield	0	0	0	272	272
Subtotal	**0**	**743**	**0**	**11,787**	**12,530**
Decontamination and Dismantlement					
Decontamination of Site Buildings	0	22,487	1,184	818	24,490
Removal of Contaminated Plant Systems	0	0	0	8,418	8,418
Subtotal	**0**	**22,487**	**1,184**	**9,236**	**32,908**
Management and Support					
Support Staff	942	9,433	68,187	5,323	83,884
DOC Staff	7,579	0	3,032	18,737	29,348
Consultant/Other Staff	0	0	0	190	190
Termination Survey Costs	0	0	0	1,916	1,916
Regulatory Costs	561	582	2,443	1,608	5,194
Special Tools and Equipment	5,216	0	0	0	5,216
Environmental Monitoring Costs	0	47	3,968	130	4,145
Laundry Services	0	496	990	1,438	2,925
Maintenance Allowance	0	0	1,402	0	1,402
Small Tools and Minor Equipment	0	15	0	411	426
Nuclear Liability Insurance	0	2,695	54,329	3,199	60,223
Property Taxes	0	0	7,348	240	7,588
DOC Mobilization/Demobilization Costs	0	0	0	4,144	4,144
Steam Generator Undistributed Costs	0	0	0	328	328
Chemical Decon	0	414	0	0	414
Plant Power Usage	0	1,011	847	2,771	4,629
Subtotal	**14,298**	**14,693**	**142,546**	**40,435**	**211,972**
LLW Packaging	0	167	105	3,360	3,631
LLW Shipping	0	1,518	1	4,322	5,841
LLW Burial/Waste Vendor	0	17,251	422	79,355	97,028
Total	14,298	56,859	144,258	148,495	363,910

Table 15. Reference BWR Decommissioning Cost Distribution by Time Period—DECON

Decommissioning Activity	Period 1 (2.5 Years) Planning & Preparation	Period 2 (1.1 Years) Plant Deactivation	Period 3 (3.4 Years) Safe Storage Operations	Period 4 (1.7 Years) Dismantlement	Duration (8.8 Years) Total Cost
	Decommissioning Cost (2000 $thousands)				
Radioactive Component Removal					
RPV Internals	0	1,227	0	0	1,227
Reactor Pressure Vessel and Insulation	0	0	0	287	287
Sacrificial Shield	0	0	0	1,177	1,177
Recirculation Pumps	0	0	0	25	25
RCS Piping	0	0	0	1,635	1,635
RCS Piping Insulation	0	0	0	0	0
Main Turbine	0	0	0	382	382
Main Turbine Condenser	0	0	0	776	776
Moisture Separator Reheaters	0	0	0	188	188
Feedwater Heaters	0	0	0	104	104
Turbine Feed Pumps	0	0	0	21	21
Structural Beams, Plates, & Cable Trays	0	0	0	691	691
Spent Fuel Racks	0	0	0	1,298	1,298
Subtotal	**0**	**1,227**	**0**	**6,585**	**7,812**
Decontamination and Dismantlement					
Decontamination of Site Buildings	0	20,811	0	1,144	21,954
Removal of Contaminated Plant Systems	0	0	0	14,687	14,687
Subtotal	**0**	**20,811**	**0**	**15,831**	**36,642**
Management and Support					
Support Staff	1,336	26,154	2,253	7,689	37,432
DOC Staff	7,579	0	1,516	17,694	26,789
Consultantss/Other Staff	0	0	0	190	190
Termination Survey Costs	0	0	0	1,661	1,661
Regulatory Costs	561	677	136	959	2,333
Special Tools and Equipment	5,374	0	0	0	5,374
Environmental Monitoring Costs	0	92	26	130	247
Laundry Services	0	826	50	1,700	2,576
Small Tools and Minor Equipment	0	25	0	430	454
Nuclear Liability Insurance	0	5,016	3,202	3,199	11,417
DOC Mobilization/Demobilization Costs	0	0	0	4,144	4,144
Chemical Decontamination	0	328	0	0	328
Plant Power Usage	0	1,566	25	2,219	3,810
Subtotal	**14,850**	**34,684**	**7,208**	**40,015**	**96,757**
LLW Packaging	0	217	0	5,506	5,722
LLW Shipping	0	1,089	0	444	1,534
LLW Burial/Waste Vendor	0	18,064	0	174,781	192,845
Total	**14,850**	**76,092**	**7,208**	**243,162**	**341,312**

Table 16. Reference BWR Decommissioning Cost Distribution by Time Period—SAFSTOR

Decommissioning Activity	Decommissioning Cost (2000 $thousands)				
	Period 1 (2.5 Years) Planning & Preparation	Period 2 (1.2 Years) Plant Deactivation	Period 3 (57.1 Years) Safe Storage Operations	Period 4 (1.7 Years) Dismantle-ment	Duration (62.5 Years) Total Cost
Radioactive Component Removal					
RPV Internals	0	1,227	0	0	1,227
Reactor Pressure Vessel and Insulation	0	0	0	287	287
Sacrificial Shield	0	0	0	1,177	1,177
Recirculation Pumps	0	0	0	25	25
RCS Piping	0	0	0	1,635	1,635
RCS Piping Insulation	0	0	0	0	0
Main Turbine	0	0	0	382	382
Main Turbine Condenser	0	0	0	776	776
Moisture Separator Reheaters	0	0	0	188	188
Feedwater Heaters	0	0	0	104	104
Turbine Feed Pumps	0	0	0	21	21
Structural Beams, Plates, & Cable Trays	0	0	0	691	691
Spent Fuel Racks	0	0	0	1,298	1,298
Subtotal	**0**	**1,227**	**0**	**6,585**	**7,812**
Decontamination and Dismantlement					
Decontamination of Site Buildings	0	20,811	715	428	21,954
Removal of Contaminated Plant Systems	0	0	0	14,687	14,687
Subtotal	**0**	**20,811**	**715**	**15,116**	**36,642**
Management and Support					
Support Staff	1,336	26,154	101,702	9,171	138,364
DOC Staff	7,579	0	3,032	17,694	28,305
Consultants/Other Staff	0	0	0	190	190
Termination Survey Costs	0	0	0	1,661	1,661
Regulatory Costs	561	677	22,378	959	24,575
Special Tools and Equipment	5,374	0	0	0	5,374
Environmental Monitoring Costs	0	92	4,123	130	4,344
Laundry Services	0	826	981	1,843	3,651
Maintenance Allowance	0	0	1,465	0	1,465
Small Tools and Minor Equipment	0	25	0	430	454
Nuclear Liability Insurance	0	5,016	53,783	3,199	61,997
Property Taxes	0	0	0	0	0
DOC Mobilization/Demobilization Costs	0	0	0	4,144	4,144
Chemical Decontamination	0	328	0	0	328
Plant Power Usage	0	1,566	685	2,219	4,471
Subtotal	**14,850**	**34,684**	**188,150**	**41,640**	**279,324**
LLW Packaging	0	217	38	5,467	5,722
LLW Shipping	0	1,089	26	418	1,534
LLW Burial/Waste Vendor	0	18,064	270	172,768	191,103
Total	14,850	76,092	189,200	241,995	522,136

c) The reviewer should compare the licensee's estimates with the tabulations of typical waste volumes, packaging costs, shipping costs, and burial costs for the reference PWR and the reference BWR (see NUREG/CR-5884 and NUREG/CR-6174) as shown in Tables 17 and 18 below. The most recent update of NUREG-1307 includes a discussion and analysis of recently-used waste volume reduction technologies. This analysis includes an option that assumes the utilization of waste vendors to process limited amounts of LLW that meets certain specifications. The updated NUREG-1307 also give the latest radioactive waste disposal unit costs and adjustment factors for waste burial at other licensed disposal sites.

Table 17. Typical Waste Burial Cost and Volumes—Reference PWR

Decommissioning Activity	Waste Volume (ft^3)	Packaging Cost (2000 $ millions)	Shipping Cost (2000 $ millions)	Burial Cost (2000 $ millions)
DECON				
Removal of NSSS	123,700	1.38	5.22	49.00
Removal of Contaminated Plant	75,500	1.14	0.28	25.52
Decontamination of Site Buildings	72,500	1.00	0.28	19.25
Dry Active Waste	19,500	0.11	0.06	4.74
Total	291,200	3.63	5.84	98.52
SAFSTOR				
Removal of NSSS	123,700	1.38	5.22	47.71
Removal of Contaminated Plant	75,500	1.14	0.28	25.33
Decontamination of Site Buildings	72,500	1.00	0.28	19.25
Dry Active Waste	19,500	0.11	0.06	4.74
Total	291,200	3.63	5.84	97.03

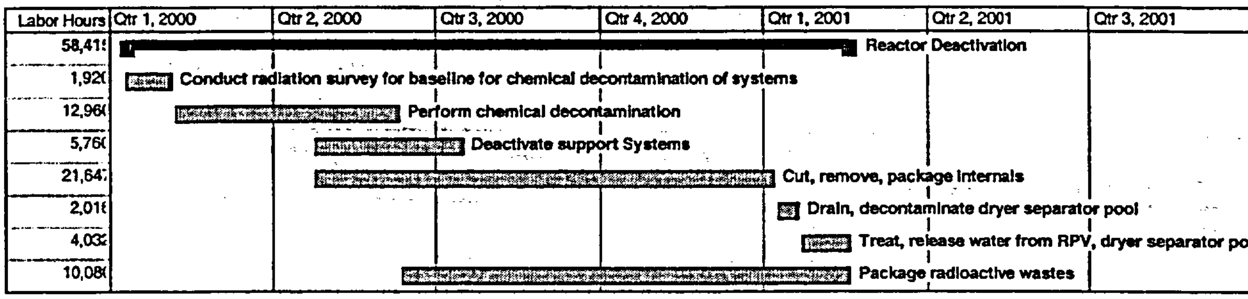
Table 18. Typical Waste Burial Cost and Volumes—Reference BWR

Decommissioning Activity	Waste Volume (ft^3)	Packaging Cost (2000 $ millions)	Shipping Cost (2000 $ millions)	Burial Cost (2000 $ millions)
DECON				
Removal of NSSS	293,200	3.04	1.37	113.85
Removal of Contaminated Plant	149,000	2.06	0.07	53.77
Decontamination of Site Buildings	57,700	0.42	0.08	16.48
Other Dry Active Waste	34,200	0.19	0.02	8.74
Total	534,100	5.72	1.53	192.84
SAFSTOR				
Removal of NSSS	293,200	3.04	1.37	113.81
Removal of Contaminated Plant	149,000	2.06	0.07	52.07
Decontamination of Site Buildings	57,700	0.42	0.08	16.48
Other Dry Active Waste	34,200	0.19	0.02	8.74
Total	534,100	5.72	1.53	191.10

d) The reviewer should compare the licensee's schedule of decommissioning activities with the schedules shown in Figures 2 and 3 to ensure sufficient level of detail to

determine the task scheduling, task durations, and labor requirements for decommissioning activities.

Figure 1. Schedule of Activities During Reference BWR Deactivation (Period 2)



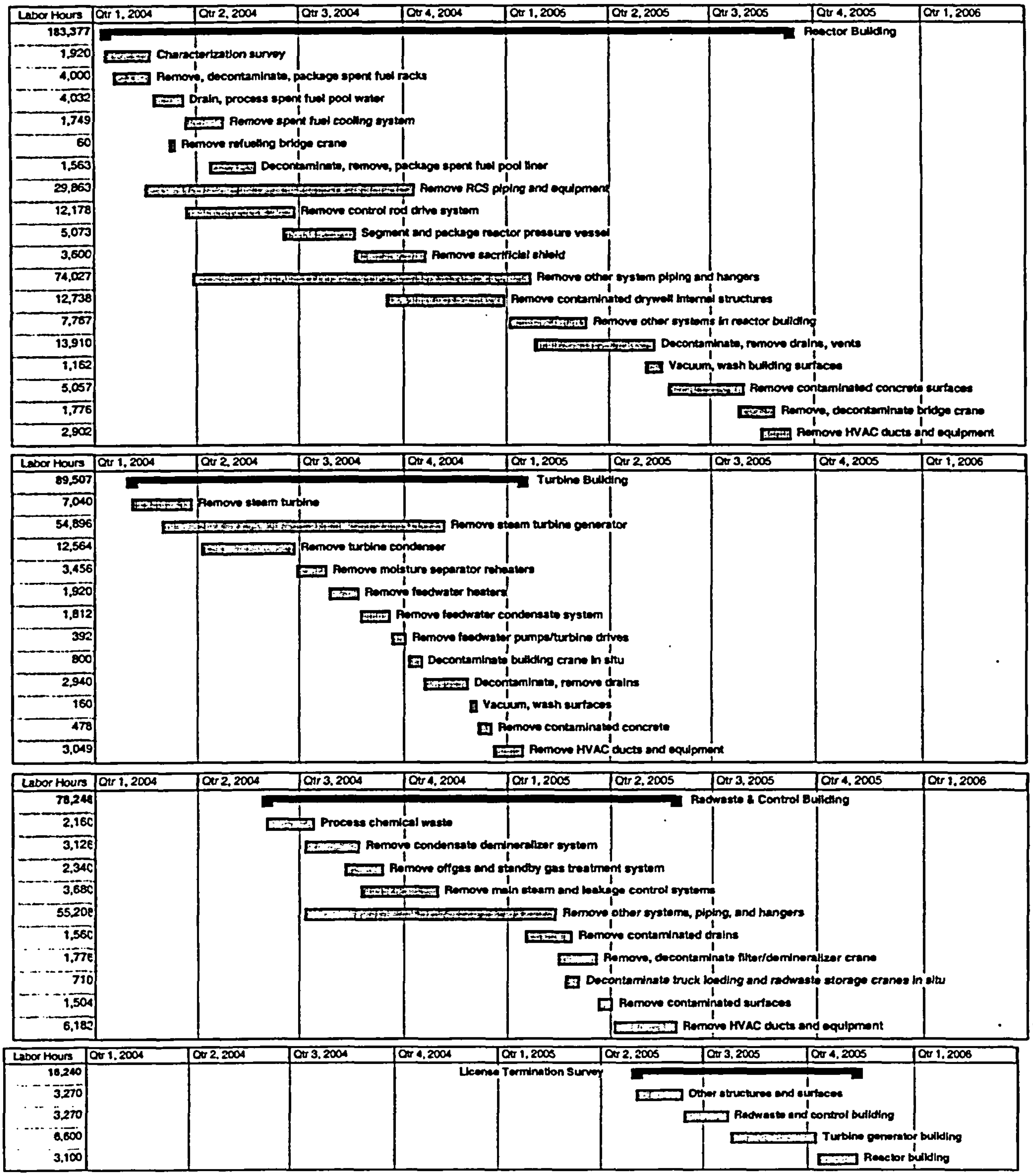


Figure 2. Schedule of Activities During Reference BWR Dismantlement (Period 4)

e) The reviewer should compare the licensee's estimated labor needs and labor costs by time period with those shown below in Table 19 for the reference PWR and reference BWR (see NUREG/CR-5884 and NUREG/CR-6174) for both decommissioning scenarios, DECON and SAFSTOR. Labor needs (in person-years per period) and labor costs (in millions of 2000 dollars) are grouped into two labor categories, decommissioning crews and management/support staff.

Table 19. Labor Needs and Labor Costs

	Labor Needs (person-yrs) and Labor Costs (2000 $millions)									
	Period 1		Period 2		Period 3		Period 4		Total	
	(Labor Need)	(Labor Cost)	(Labor Need)	(Labor Cost)	(Labor Need)	(Labor Cost)	(Labor Need)	(Labor Cost)	(Labor Need)	(Labor Cost)
PWR DECON										
Decommissioning Crews	0.0	0.0	16.0	23.2	0.0	0.0	122.0	22.2	138.0	45.4
Management/Support Staff	55.5	8.5	112.7	9.4	42.9	4.5	169.0	26.2	380.1	48.6
Total	55.5	8.5	128.7	32.7	42.9	4.5	290.9	48.4	518.1	94.1
PWR SAFSTOR										
Decommissioning Crews	0.0	0.0	16.0	23.2	2.1	1.2	119.9	21.0	138.0	45.4
Management/Support Staff	55.5	8.5	112.7	9.4	936.9	71.2	181.0	26.2	1,286.0	115.3
Total	55.5	8.5	128.7	32.7	938.9	72.4	300.9	47.2	1,424.0	160.8
BWR DECON										
Decommissioning Crews	0.0	0.0	16.7	22.0	0.0	0.0	168.7	22.4	185.4	44.5
Management/Support Staff	55.5	8.9	219.6	26.2	27.5	3.8	176.6	27.2	479.2	66.1
Total	55.5	8.9	236.3	48.2	27.5	3.8	345.3	49.7	664.6	110.5
BWR SAFSTOR										
Decommissioning Crews	0.0	0.0	16.7	22.0	1.3	0.7	167.3	21.7	185.4	44.5
Management/Support Staff	55.5	8.9	219.6	26.2	960.9	104.7	191.8	28.7	1,427.8	168.5
Total	55.5	8.9	236.3	48.2	962.2	105.4	359.2	50.4	1,613.2	213.0

f) The reviewer should compare the licensee's estimate of radwaste volumes with the approximate estimates made in the reevaluated analyses of the NRC reference reactors (see NUREG/CR-5884 and NUREG/CR-6174). Those analyses assumed no significant volume reductions and used waste containers, transportation and waste burial rates typical for 1993. The distribution range of waste burial volumes by waste classes A, B & C, and greater than class C (GTCC) are shown below in Table 20. The table displays the combined volume of classes B & C. All Class A and B & C wastes are assumed to be disposed at licensed LLW burial sites with GTCC waste being stored in a licensed geologic repository.

Table 20. Burial Volumes by Waste[a]

Waste Class	Reference PWR		Reference BWR	
	Volume (ft^3)	Percent	Volume (ft^3)	Percent
Class A	280,900	96.5	514,900	96.4
Class B&C	9,900	3.4	19,200	3.6
GTCC	400	0.13	200	0.04
Total	291,200	100.0	534,100	100.0

[a] Untreated (prior to volume reduction) volumes.

(5) Evaluation Findings

Using the acceptance criteria in C.3(3) and the review procedure in C.3(4) of this section as a basis, the NRC staff reviewer shall verify that sufficient information has been provided to satisfy the requirement of the underlying regulations (10 CFR 50.82(a)(8)(iii) or 10 CFR 50.75(b)). The SSCE shall be considered deficient if (1) the decommissioning cost estimate is less than the financial assurance amount required by 10 CFR 50.75(c) and adequate justification is not provided, (2) the reviewer cannot verify that all the information identified under the Acceptance Criteria has been provided, or (3) in the reviewer's judgment the SSCE submitted does not appear reasonable based on a comparison with the information provided from the reference PWR or BWR, considering the variation in plant sizes and decommissioning techniques. If deficiencies are discovered, the reviewer should provide this information to the NRC project manager for the plant. The NRC project manager will inform the licensee in writing of the additional information that is needed to ensure that the SSCE can be adequately evaluated. The reviewer documents the findings of his/her review of the SSCE in a memorandum to his/her branch chief with a copy to the NRC project manager for the plant.

(6) Implementation

The method described in this SRP will be used by the staff in evaluating conformance with the NRC's regulations, except when the licensee proposes an acceptable alternative for complying with specified portions of the regulations.

4. LICENSE TERMINATION PLAN UPDATED SITE-SPECIFIC COST ESTIMATE

According to 10 CFR 50.82(a)(9)(ii)(F), a licensee must submit "[a]n updated site-specific estimate of remaining decommissioning costs..." as part of an LTP. According to 10 CFR 50.82(a)(9)(i), among other things, the licensee must submit the LTP at least 2 years before termination of the license. The estimated remaining costs of decommissioning must be compared with the present funds set aside for decommissioning. The financial assurance instrument required per 10 CFR 50.75(b)(1) must be funded at least to the amount of the cost estimate. If there is a deficit in present funding, the LTP must indicate the means for ensuring adequate funds to complete the decommissioning. Information on the preparation of an LTP may be found in Regulatory Guide 1.179, "Standard Format and Content of License Termination Plans for Nuclear Power Reactors"

and NUREG-1700, "Standard Review Plan for Evaluating Nuclear Power Reactor License Termination Plans." NUREG-1700, "Update of Site-Specific Costs" addresses the information necessary to support the cost estimate. The update of the site specific costs may be in summary form provided the supporting information had been previously submitted and is referenced. The supporting information may have been submitted as part of the SSCE or the expected cost estimated submitted with the PSDAR.

Licensees who plan to use a period of storage or surveillance (SAFSTOR) are required by 10 CFR 50.82(a)(8)(iv) to provide a means of adjusting cost estimates and associated funding levels over the period of storage or surveillance. If the time period covered by the updated SSCE includes a period of SAFSTOR, the reviewer should ensure that the licensee has included a description of its means of adjustment in the updated SSCE. The cost estimate reviewer should consult with a financial assurance reviewer to determine if the means described by the licensee provide adequate assurance that funds will be available for decommissioning activities at the time they are needed. Cost estimates associated with requests for license termination under restricted release conditions and for entombment will be handled on a case-by-case basis.

(1) Review Responsibilities

Primary—Division of Waste Management, Office of Nuclear Material Safety and Safeguards

Secondary—Financial Reviewer, Financial and regulatory Analysis Section, Reactor Policy and Rulemaking Branch, Division of Regulatory Improvement Programs, Office of Nuclear Reactor Regulation, or as assigned.

(2) Areas of Review

This SRP directs the staff's review of the "an updated site-specific estimate of remaining decommissioning costs" that is required by 10 CFR 50.82(a)(9)(ii)(F) as part of an LTP. The intent of this cost estimate is to provide the NRC with an up-to-date site-specific estimate of remaining decommissioning costs to terminate the license. A complete SSCE will have been submitted within 2 years following permanent cessation of operations.

(3) Acceptance Criteria

In accordance with 10 CFR 50.82(a)(9)(i), a licensee must submit its LTP at least 2 years before termination of the license. The LTP submittal must be a supplement to the final safety analysis report (FSAR) or equivalent. In accordance with 10 CFR 50.82(a)(9)(ii)(F), the LTP must contain "an updated site-specific estimate of remaining decommissioning costs...."

The LTP cost estimate should contain, for those activities remaining to be completed, an updated, equally detailed version of the site-specific estimate previously submitted to and accepted by the NRC. The updated cost estimate in the LTP should include the following items:

- Estimated costs of remaining radiological decontamination activities
- Estimated costs of dismantling remaining contaminated equipment and structures

- Estimated costs for disposal of remaining radioactive waste
- Estimated final survey costs and license termination survey costs
- If the site is released for restricted use, the estimated costs for controls and a description of the financial assurance mechanisms used to ensure the availability of funds when they are needed

A licensee may include nondecommissioning costs in its LTP for information purposes. However, if the licensee does so, such costs should be clearly identified as costs in addition to decommissioning costs.

(4) Review Procedures

The reviewer will use the following process to determine that the submitted LTP decommissioning cost estimate considers, in adequate detail, all major factors that could affect the total remaining cost to decommission.

The reviewer should review the LTP decommissioning cost estimate to determine if it is sufficiently detailed to allow the reviewer to assess its adequacy. To make this assessment, the reviewer should confirm that the cost estimate is provided in current year (estimate year) dollars and that escalation of the LLW disposition costs is considered separately from the general inflation rate applicable to labor, material, and energy costs. The reviewer should be aware of the escalation rates used in the current revision of NUREG-1307. The reviewer should also confirm that the cost estimate accounts for the entire decommissioning work scope, but not for items that are outside the scope of the decommissioning process, such as the maintenance and storage of spent fuel in the spent fuel pool, the design or construction of spent fuel dry storage facilities, or other activities not directly related to the long-term storage, radiological D&D of the facility, or radiological decontamination of the site.

The reviewer should ensure that (1) the licensee has identified the remaining dismantlement activities that are necessary to complete the decommissioning of the facility/site, as required by 10 CFR 50.82(a)(9)(ii)(B), and (2) the licensee has identified site areas requiring remediation and has in place an organization to safely perform the remediation as required by 10 CFR 50.82(a)(9)(ii)(C). The licensee should have provided costs for each of the following cost elements identified below.

Cost Elements

- Cost assumptions used, including a contingency factor
- Major remaining decommissioning activities and tasks
- Estimated costs of radiological decontamination and removal of remaining radioactive equipment and structures
- Estimated costs of waste disposal, including applicable disposal site surcharges and transportation costs
- Estimated final survey costs
- Estimated total costs

The previous SRP for the SSCE gives further details on this analysis, including the specific information that should have been provided and descriptions of the type of information and anticipated values.

(5) Evaluation Findings

Using the acceptance criteria in C.4(3) and the review procedures in C.4(4) of this section as a basis, the NRC staff reviewer shall verify that sufficient information has been provided to satisfy the requirements of the underlying regulations (10 CFR 50.82(a)(9)(ii)(F)). The LTP decommissioning cost estimate shall be considered deficient if any of the costs listed in the acceptance criteria are not adequately addressed. If deficiencies are discovered, the reviewer should provide this information to the NRC project manager for the plant. The NRC project manager will inform the licensee in writing of the additional information that is required by the regulations before major decommissioning activities can begin. The reviewer documents the findings of his/her review of the LTP decommissioning cost estimate in a memorandum to his/her branch chief with a copy to the NRC project manager for the plant. The review should be forwarded for inclusion in the LTP evaluation.

(6) Implementation

The method described in this SRP will be used by the staff in evaluating conformance with the Commission's regulations, except when the licensee proposes an acceptable alternative for complying with specified portions of the regulations.

D. REFERENCES

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[1] Single copies of regulatory guides may be obtained free of charge by writing the Reproduction and Distribution Services Section, OCIO, USNRC, Washington, DC 20555-0001, or by fax to (301) 415-2289, or by email to DISTRIBUTION@NRC.GOV. Copies of guides are available for inspection or copying for a fee from the NRC Public Document Room at 11555 Rockville Pike, Rockville, MD; the PDR's mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; email PDR@NRC.GOV.

[2] Copies are available at current rates from the U.S. Government Printing Office, P.O. Box 37082, Washington, DC 20402-9328 (telephone (202) 512-1800); or from the National Technical Information Service by writing NTIS at 5285 Port Royal Road, Springfield, VA 22161; http://www.ntis.gov/ordernow; telephone (703)487-4650;. Copies are available for inspection or copying for a fee from the NRC Public Document Room at 11555 Rockville Pike, Rockville, MD; the PDR's mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; email is PDR@NRC.GOV.

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10. SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

This Standard Review Plan (SRP) for decommissioning cost estimates provides guidance to Office of Nuclear Reactor Regulation (NRR) and Office of Nuclear Material Safety and Safeguards (NMSS) staff on how to evaluate each of the decommissioning cost estimates that are required to be provided by the power reactor licensees. The SRP includes guidance on evaluating decommissioning costs for both pressurized water reactors (PWRs) and boiling water reactors (BWRs). The SRP is divided into sections that are keyed to the sections in Regulatory Guide-1085, "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors," which was developed to provide guidance to licensees on decommissioning cost estimates. Each section of this NUREG is a separate SRP and presents the areas of review, acceptance criteria, review procedures, and evaluation findings for each of the decommissioning cost estimates required by 10CFR50.75 and 10CFR50.82.

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STANDARD FORMAT AND CONTENT OF DECOMMISSIONING COST ESTIMATES FOR NUCLEAR POWER REACTORS

A. INTRODUCTION

Decommissioning means permanently removing a nuclear facility from service and reducing radioactive material on the licensed site to levels that would permit termination of the license issued by the U.S. Nuclear Regulatory Commission (NRC). The NRC amended its regulations on decommissioning procedures that lead to termination of an operating license for nuclear power reactors, as specified in Title 10, Section 50.82, of the *Code of Federal Regulations* (10 CFR 50.82). The amended regulations became effective on July 29, 1996. This rulemaking included changes to 10 CFR Part 2, "Rules of Practice for Domestic Licensing Proceedings and Issuance of Orders"; Part 50, "Domestic Licensing of Production and Utilization Facilities"; and Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions." Among other relevant topics, these regulations contain requirements related to submission of decommissioning cost estimates. The purpose of this regulatory guide is to provide licensees with guidance on a method that the NRC staff finds acceptable for use in preparing the following required cost estimates as specified in the regulations:

- The preliminary decommissioning cost estimate (hereinafter referred to as the preliminary cost estimate) is to be submitted at or about 5 years prior to the projected end of operations [10 CFR 50.75(f)(2)].
- The expected cost estimate contained in the Post-Shutdown Decommissioning Activities Report (PSDAR) is required to be submitted (with the PSDAR) prior to or within 2 years of permanent cessation of operations [10 CFR 50.82(a)(4)(i)].

- The site-specific decommissioning cost estimate is to be submitted within 2 years following permanent cessation of operations [10 CFR 50.82(a)(8)(iii)].
- The updated site-specific cost estimate for remaining decommissioning activities is to be included in the License Termination Plan (LTP), which must be submitted at least 2 years before termination of the license [10 CFR 50.82(a)(9)(ii)(F)].

The NRC staff suggests that licensees use the standard format described in this regulatory guide to facilitate preparation and NRC review of the required cost estimates.

This regulatory guide applies only to power reactor licensees. The regulations for non-power reactor licensees are given in 10 CFR 50.82(b).

The 1996 amendment to the NRC's regulations on decommissioning procedures requires that power reactor licensees who were engaged in decommissioning at the time the regulation became effective must convert to, and comply with, the amended regulation. All power reactor licensees are required to comply with the decommissioning procedures specified in these regulations, and no "grandfathering" considerations are applicable.

The NRC's decommissioning regulations address the minimum decommissioning funding requirements necessary to achieve termination of the license issued under 10 CFR Part 50. The NRC's definition of decommissioning does not include other activities related to facility deactivation and site closure, including operation of the spent fuel storage pool, construction and/or operation of an independent spent fuel storage installation (ISFSI), demolition of decontaminated structures, and/or site restoration activities after residual radioactivity has been removed. Accordingly, this regulatory guide does not address such "non-NRC decommissioning costs"; nonetheless, this regulatory guide does address the cost to decontaminate an ISFSI licensed under the General License.

Rules applicable to managing and providing funding for the management of irradiated fuel following shutdown are contained in 10 CFR 50.54(bb). Regulations applicable to an ISFSI facility are contained in 10 CFR Part 72, "Licensing Requirements for the Independent Storage of Spent Nuclear Fuel and High-Level Radioactive Waste." Site restoration activities that do not involve the removal of residual radioactivity necessary to terminate the NRC license are outside the scope of NRC regulation.

This regulatory guide contains information collections that are covered by the requirements of 10 CFR Part 50, which the Office of Management and Budget (OMB) approved under OMB control number 3150-0011. The NRC may neither conduct nor sponsor, and a person is not required to respond to, an information collection request or requirement unless the requesting document displays a currently valid OMB control number.

B. DISCUSSION

DECOMMISSIONING OPTIONS

The three basic methods for decommissioning are DECON, SAFSTOR, and ENTOMB. NUREG-0586, "Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities," and NUREG-0586, Supplement 1 (Ref. 1), evaluated the environmental impact of these three methods, which are summarized as follows:

(1) **DECON**: The equipment, structures, and portions of the facility and site that contain radioactive contaminants are promptly removed or decontaminated to a level that permits termination of the license after cessation of operations. (Decontamination is initiated within a couple of years after shutdown and continues until completed, usually within 7 to 10 years.)

(2) **SAFSTOR**: The facility is placed in a safe, stable condition and maintained in that state (safe storage). The facility is decontaminated and dismantled at the end of the storage period to levels that permit license termination. Therefore, the SAFSTOR determination includes consideration of those activities necessary for final decontamination and dismantlement of the facility. During SAFSTOR, a facility is left intact or may be partially dismantled, but the fuel is removed from the reactor vessel and radioactive liquids are drained from systems and components. Radioactive decay occurs during the SAFSTOR period, thereby reducing the quantity of contamination and radioactivity that must be disposed of during decontamination and dismantlement (D&D). The SAFSTOR determination also includes D&D of the facility at the end of the storage period.

(3) **ENTOMB**: Radioactive structures, systems, and components are encased in a structurally long-lived substance, such as concrete. The entombed structure is appropriately maintained, and monitored (through continued surveillance) until the radioactivity decays to a level that permits termination of the license. Because most power reactors will have radionuclides in concentrations exceeding the limits for unrestricted use even after 100 years, and because current regulations require decommissioning to be completed within 60 years of cessation of operation, the NRC will handle entombment requests on a case-by-case basis.

Although the selection of the decommissioning option is up to the licensee, the NRC requires the licensee to reevaluate its selection if the option (1) cannot be completed as described, (2) cannot be completed within 60 years of the permanent cessation of plant operations, (3) includes activities that would endanger the health and safety of the public by being outside of the NRC's health and safety regulations, or (4) will result in a significant impact to the environment.

DECOMMISSIONING COST ESTIMATES

The following regulatory requirements relate to submitting a decommissioning cost estimate:

- 10 CFR 50.75(f)(2) requires that a licensee "…shall at or about 5 years prior to the projected end of operations submit [to the NRC] a preliminary decommissioning cost estimate which includes an up-to-date assessment of the major factors that could affect the cost to decommission." 10 CFR 50.75(f)(4) requires a licensee to include plans to adjust funding levels to demonstrate a reasonable level of financial assurance, if necessary, in the preliminary cost estimate.

  In addition, 10 CFR 50.75(c) specifies that the initial certification amount of funds for decommissioning must be based on the amounts specified in 10 CFR 50.75(c), which represents the minimum funding level that applicants and licensees must meet. However to meet the requirements of 10 CFR 50.75(c), a power reactor licensee may submit a certification based on a site-specific cost estimate, which may be more (but not less) than the amount specified in 10 CFR 50.75(b)(1) when a higher funding level than 10 CFR 50.75(c) is desired. The basis for any increases should be provided. Although this site-specific cost estimate is not the same site-specific cost estimate required by 10 CFR 50.82(a)(8)(iii), it should address many areas identified in Section 3 of this document; however, the level of detail will be less and the level of uncertainty may vary.

- 10 CFR 50.82(a)(4)(i) requires a licensee to provide "…an estimate of expected costs…" for the activities being proposed in the PSDAR. As previously stated, the PSDAR is to be submitted prior to or within 2 years following permanent cessation of operations. Regulatory Guide 1.185, "Standard Format and Content for Post-Shutdown Decommissioning Activities Report" (Ref. 2), identifies the types of information to be included in the PSDAR. The cost estimate may be a site-specific cost estimate or the amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c), as currently reported to the NRC on a calendar-year basis at least once every 2 years in accordance with 10 CFR 50.75(f)(1).

- 10 CFR 50.82(a)(8)(iii) requires a licensee to provide a site-specific decommissioning cost estimate within 2 years following permanent cessation of operations. (This requirement may be satisfied by including a site-specific cost estimate as part of the PSDAR.)

  In addition, 10 CFR 50.75(c) specifies that the initial certification amount of funds for decommissioning must be based on the amounts specified in 10 CFR 50.75(c)(1), which represents the minimum funding level that applicants and licensees must meet. The site-specific cost estimate submitted within 2 years following permanent cessation of operations may be significantly larger than the funding level based on the formula. If the site-specific cost estimate results in a funding level that differs from the amount specified in 10 CFR 50.75(c), the licensee must provide the basis for the change.

- 10 CFR 50.82(a)(9)(ii)(F) requires a licensee to provide "an updated site-specific estimate of remaining decommissioning costs…" as part of a license termination plan (LTP). 10 CFR 50.82(a)(9)(i) requires a licensee to submit its LTP at least 2 years before termination of the license.

As provided in 10 CFR 50.82(a)(8)(ii), a licensee may withdraw funds from the decommissioning trust fund up to a cumulative total of 3 percent of the generic amount calculated under 10 CFR 50.75(c) for decommissioning planning purposes at any time without prior notification to the NRC. After submittal of the certifications of permanent shutdown and fuel removal required under 10 CFR 50.82(a)(1) and commencing 90 days after the NRC has received the PSDAR, the licensee may use up to an additional 20 percent of the decommissioning funds prescribed in 10 CFR 50.75(c) for decommissioning purposes. The licensee is prohibited from using the remaining 77 percent of the generic decommissioning funds until a site-specific decommissioning cost estimate is submitted to the NRC. In addition, 10 CFR 50.82(a)(8)(i) limits use of the decommissioning funds to legitimate radiological decommissioning expenses that neither reduces the value of the trust fund below that necessary to place and maintain the reactor in a safe storage condition, nor impacts the licensee's ability to complete funding of the trust to ultimately release the site and terminate the license.

C. REGULATORY POSITION

The major types of cost estimates affecting the licensee are (1) the preliminary cost estimate, (2) the estimate of expected costs presented in the PSDAR, (3) the site-specific decommissioning cost estimate, and (4) the updated site-specific estimate of remaining decommissioning costs.

The licensee is reminded that 10 CFR 50.2 defines decommissioning as the safe removal of a facility or site from service and the reduction of residual radioactivity to levels that permit release of the site and termination of the license. For example, removing uncontaminated material, such as soil or a wall, to gain access to contamination to be removed would be a legitimate decommissioning cost. However, the costs of demolition of decontaminated structures, site restoration activities, or other activities not involved with removing the facility from service or reducing residual radioactivity are not included within the NRC's definition of decommissioning costs, and are not included in the amount of funds that 10 CFR 50.75 requires to be placed in the plant's decommissioning fund. If a licensee sets aside funds in the trust that are supporting non-NRC decommissioning activities, the sub-accounts under the trust must be clearly designated.

1. PRELIMINARY COST ESTIMATE PRIOR TO THE END OF OPERATIONS

The preliminary cost estimate, required by 10 CFR 50.75(f)(2), must be submitted at or about 5 years before the projected end of operations. The intent of the preliminary estimate is to provide the NRC with an up-to-date estimate of decommissioning costs and identify major factors that would impact the cost of the decommissioning. The licensee will already have submitted a cost estimate for establishing a fund for decommissioning as required by 10 CFR 50.75(b). This estimate will have been revised periodically during operation and may be used in preparing the preliminary cost estimate. For the preliminary cost estimate, the NRC will compare the estimated costs with the minium decommissioning trust fund amount derived from the formula and, if the preliminary cost estimate is greater than the amount in the decommissioning trust fund, the licensee should include a discussion of the mechanism for adjusting the level of funds to demonstrate that funds will be available for use at the time of permanent shutdown.

The preliminary cost estimate may be a new or previously developed site-specific cost estimate, provided that the estimate contains the information specified in 10 CFR 50.75(f)(2) and represents the cost to decommission the facility. The preliminary cost estimate information may be in summary form, as long as the supporting basis has previously been submitted and is referenced.

The projected end of operations need not be the same as the expiration date of the operating license if a licensee chooses to permanently cease operations at an earlier date. In some cases, a licensee may shut down prematurely and submit its certification of permanent cessation of operations, as required by 10 CFR 50.82(a)(1), more than 5 years prior to the expiration date of the operating license. In this event, the requirement of 10 CFR 50.75(f)(2) to submit a preliminary cost estimate is not applicable. If a prematurely shutdown licensee chooses to submit its PSDAR along with its certification of permanent shutdown, it could choose to submit its preliminary cost estimate as the estimate of expected costs required for the PSDAR. This action would satisfy the requirements of 10 CFR 50.82(a)(4)(i).

The information in the preliminary cost estimate should be similar to that submitted for the site-specific cost estimate; however, the level of detail will be less and the level of uncertainty may vary. For example, the NRC recognizes that many items (such as waste disposal cost) are difficult to estimate and may vary during the 5 years prior to shutdown. The preliminary cost estimate should include the following:

- a detailed discussion of the decommissioning option anticipated to be implemented (DECON, SAFSTOR, or some combination thereof), with major factors that could impact the cost of decommissioning, including major technical actions and waste disposal site availability
- a discussion of the potential for known or suspected contamination at the site that may affect the cost of decommissioning [This discussion should include an evaluation of the records of information important to decommissioning required by 10 CFR 50.75(g). Although the requirements described in 10 CFR 50.75(g) for keeping records of spills or other unusual occurrences are outside the scope of this regulatory guide, the licensee should evaluate the anticipated extent of contamination on the facility and site, based on information available in the decommissioning files. This evaluation should include descriptions of known instances of releases of contaminated materials into the facility and the external environment, along with the possible impact on decommissioning. Known environmental contamination (e.g., contamination in soil, groundwater, or surface water) should be identified.]
- a preliminary schedule that shows the major decommissioning phases and the time period over which each of the phases extends
- a summary of the total estimated decommissioning costs by decommissioning activity [This summary should include the anticipated cost of low-level waste (LLW) disposal. Table 1 of this document presents a suggested format for providing this information.]
- a comparison of the estimated cost with the minimum decommissioning fund requirement
- a discussion of the plans for adjusting the level of funds in the trust to demonstrate that funds will be available for use when needed should be included if the decommissioning trust is not fully funded

Table 1. Suggested Format for Tabulating Expected Costs

Decommissioning Activity	Estimated Decommissioning Cost (Millions of Estimate-Year Dollars)				
	Period 1 (X.X Years)	Period 2 (X.X Years)	Period 3 (X.X Years)	Period 4 (X.X Years)	Duration (X.X Years)
	Planning & Preparation	Plant Deactivation	Safe Storage Operations	Dismantle-ment	Total Cost
Radioactive Component Removal					
Decontamination and Dismantlement					
Management and Support					
LLW Costs including packaging, shipping and burial/vendor costs					
Total Cost					

2. ESTIMATE OF EXPECTED COSTS IN THE PSDAR

Prior to or within 2 years following permanent cessation of operations, the licensee is required [by 10 CFR 50.82(a)(4)(i)] to submit a PSDAR to the NRC. In addition to other prescribed content, this report must include an estimate of costs. Regulatory Guide 1.185 (Ref. 2) identifies the types of information to be contained in the PSDAR. The cost estimate may be satisfied by either of the following methods and supporting information:

(1) the amount of decommissioning funds estimated to be required by 10 CFR 50.75(b) and (c), as currently reported to the NRC on a calendar-year basis at least once every 2 years in accordance with 10 CFR 50.75(f)(1)

(2) a site-specific cost estimate

Other related but non-NRC decommissioning costs (e.g., spent fuel storage, site restoration) may be included in the estimate of costs if desired; however, the cost of radiological decommissioning as defined by 10 CFR 50.2 should be listed separately. As a separate item, the cost of placing and maintaining the facility in safe storage should be identified, along with a plan to ensure that sufficient funds will be available for this purpose, if necessary, until such time as the radioactively contaminated material is placed in an authorized waste disposal site. It should be noted that, as with the PSDAR, 10 CFR 50.82(a)(8)(iii) requires a licensee to provide a site-specific decommissioning cost estimate within 2 years following permanent cessation of operations. If the estimate of costs provided with the PSDAR is a site-specific cost estimate, this requirement can be satisfied with the PSDAR submittal.

2.1 Cost Estimate Based on Financial Assurance Amounts [10 CFR 50.75(b) and (c)]

Licensees of operating pressurized-water reactors (PWRs) and boiling-water reactors (BWRs) must provide reasonable assurance that funds will be available to accomplish decommissioning within 60 years from the date of permanent cessation of operations, as required by 10 CFR 50.82(a)(3). Reasonable assurance may be demonstrated by compliance with the requirements of 10 CFR 50.75(b), (c), (e), and (f). These requirements ensure that a licensee has financial assurance in effect for an amount that may be more (but not less) than the amount stated in the table in 10 CFR 50.75(c)(1). A licensee is required [by 10 CFR 50.75(f)(1)] to report, on a calendar-year basis at least once every 2 years, the status of its decommissioning funding. Specifically, this table demonstrates that if *P* equals the thermal power of a reactor in megawatts (MWt), the minimum financial assurance (MFA) funding amount (in millions, January 1986 dollars) is calculated as follows:

- for a PWR: $MFA = (75 + 0.0088P)$
- for a BWR: $MFA = (104 + 0.009P)$

For either a PWR or a BWR, if the thermal power of the reactor is less than 1,200 MWt, the value of *P* to be used in these equations is 1,200, whereas if the thermal power is greater than 3,400 MWt, the value of *P* to be used is 3,400.

The financial assurance amounts calculated in the above equations are based on January 1986 dollars. To account for inflation from 1986 to the current year, these amounts must be adjusted annually by multiplying by an escalation factor (ESC) described in 10 CFR 50.75(c)(2), as follows:

$$ESC\ (current\ year) = (0.65L + 0.13E + 0.22B)$$

where *L* and *E* are the ESC from 1986 to the current year for labor and energy, respectively, and are to be taken from regional data of the U.S. Department of Labor, Bureau of Labor Statistics (Refs. 3 and 4), and *B* is an annual ESC from 1986 to the current year for waste burial and is to be taken from the most recent revision of NUREG-1307, "Report on Waste Disposal Charges: Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities" (Ref. 5). The NRC updates NUREG-1307 from time to time to account for disposal charge changes. In January 1986 (the base year), using disposal costs from DOE's Hanford Reservation waste disposal site, *L*, *E*, and *B* all equaled unity; thus, the ESC itself equaled unity. (Reference 2 discusses the origin of the $0.65L$, $0.13E$, and $0.22B$ terms.) Thus,

$$MFA\ (in\ millions,\ current\ year\ dollars) = MFA \times ESC\ (current\ year)$$

2.2 Site-Specific Cost Estimates in the PSDAR

The estimate of expected decommissioning costs required for the PSDAR can be the same as the site-specific cost estimate required by 10 CFR 50.82(a)(8)(iii). The site-specific cost estimate is a detailed assessment that incorporates the cost impact of site-specific factors. (Section 3 of this document discusses the site-specific estimate.)

3. SITE-SPECIFIC COST ESTIMATE

A licensee is required [by 10 CFR 50.82(a)(8)(iii)] to submit a site-specific cost estimate within 2 years following permanent cessation of operations. The licensee may include this cost estimate with the PSDAR [10 CFR 50.82(a)(4)(i)]. In addition, a site-specific estimate may be submitted, at the discretion of the licensee, when a funding level differs from that calculated in the formula in 10 CFR 50.75(c). The site-specific cost estimate must clearly identify and provide the basis for the funding level if it differs from the formula. The site-specific cost estimate information, as well as the update of the site-specific cost, may be in summary form, as long as the supporting basis has previously been submitted and is referenced. If the cost estimate was prepared for the rate regulator, it may contain additional costs that the NRC does not consider part of the radiological decommissioning costs; however, the cost estimate is acceptable provided the costs are separated and easily distinguishable. Sections 3.1–3.4 discuss the types of information that the licensee should provide to help the NRC staff properly assess the estimate.

3.1 General Information

- Discuss the chosen decommissioning option (DECON, SAFSTOR, or some combination thereof).
- Discuss the methodology used to derive the cost estimates.
- Summarize total decommissioning costs by period. (Table 2 of this document presents a suggested format for providing this information.) Provide a separate list of the costs of items not considered part of decommissioning (such as site restoration and spent nuclear fuel storage/management).
- Compare the estimated cost with the minimum financial assurance (MFA) funding requirement.
- Discuss the plans for adjusting the level of funds in the trust should be included to demonstrate that funds will be available for use when needed if the decommissioning trust is not fully funded.
- Summarize the costs of services, supplies, and special equipment. This category should include cost estimates for protective clothing and equipment services supplied by an outside vendor. Also included under this category would be costs of purchasing or leasing specialized decommissioning equipment.
- Summarize undistributed costs, such as property taxes, consultancy costs, nuclear liability insurance costs, energy costs, annual maintenance costs for SAFSTOR phases, site termination survey costs, and regulatory costs (inspections, miscellaneous fees, etc.).

Table 2. Suggested Format for Tabulating Decommissioning Costs by Period

Decommissioning Option Chosen DECON or SAFSTOR	Decommissioning Period Duration (Years) / Decommissioning Cost (Millions of Estimate-Year Dollars)				
	Period 1 Planning & Preparation	Period 2 Plant Deactivation	Period 3 Safe Storage Operations	Period 4 Dismantlement	Total
Period Years					
Period Cost					

For the DECON option, the total decommissioning costs should be separated into the following activities:

- major radioactive component removal (reactor vessel and internals, steam generators, pressurizers, large-bore reactor coolant system piping, and other large components)
- radiological decontamination and dismantlement (D&D, which involves removing remaining radioactive plant systems, including radiological decontamination) (Tables 3 and 4 of this document present suggested formats for providing this information.)
- management and support [labor costs of support staff and decommissioning operations contractors (DOCs), energy costs, regulatory costs, small tools, insurance, etc.]
- low-level waste (LLW) costs (including packaging, shipping, and burial/waste vendor costs)
- groundwater and soil remediation, if any
- final radiological survey costs
- contingency (allowance for unexpected costs)

Table 3. Suggested Format for Listing Contaminated Equipment and Piping

Equipment Category[a]	Length of Piping in Feet or Number of Items in Each Category
Piping diameter > 3 inches	
Piping diameter # 3 inches	
Valves > 3 inches	
Valves # 3 inches	
Tanks of all sizes	
Pumps > 100 pounds	
Pumps # 100 pounds	
Heat exchangers > 100 pounds	
Heat exchangers # 100 pounds	
Electrical components > 100 pounds	
Electrical components # 100 pounds	
Miscellaneous components > 100 pounds	
Miscellaneous components # 100 pounds	
Large piping hanger for pipes > 4 inches in diameter	
Small piping hanger for pipes # 4 inches in diameter	

(a) The equipment categories shown here as examples. Any reasonable method of categorization is acceptable.

Table 4. Suggested Format for Listing Concrete and Metal Surfaces that Require Radiological Decontamination or Removal

Building or Location	Area of Concrete Decontaminated (ft^2)	Volume of Concrete Removed (ft^3)	Area of Metal Surfaces Decontaminated (ft^2)	Volume of Metal Surfaces Removed (ft^3)

For the SAFSTOR option, the decommissioning costs should also be separated into the following time periods, or a similar set of decommissioning time periods:

- pre-decommissioning engineering and planning/plant deactivation (all activities from engineering and planning through defueling and layup to complete the placement of the reactor into permanent shutdown condition)
- extended safe storage operations (safe storage monitoring of the facility until dismantlement begins); if storage or monitoring of spent fuel is included in the cost estimate, it should be shown separately
- final radiological D&D (radiological D&D of radioactive systems and structures required for license termination, including demolition for the purposes of reducing residual radioactivity); if demolition of decontaminated structures and site restoration activities are included in the cost estimate, they should be shown separately

Table 1 provides an example of a format for tabulating costs for either DECON or SAFSTOR. Tables 5 and 6 provide suggested formats for tabulating decommissioning cost for both PWR and BWR component cost.

Table 5. Suggested Format for Tabulating PWR Decommissioning Costs by Period

Decommissioning Activity	Decommissioning Cost (Thousands of Estimate-Year Dollars)				
	Period 1 (X.X Years) Planning & Preparation	Period 2 (X.X Years) Plant Deactivation	Period 3 (X.X Years) Safe Storage Operations	Period 4 (X.X Years) Dismantlement	Duration (X.X Years) Total Cost
Radioactive Component Removal					
Removal of RPV Internals					
Removal of Reactor Pressure Vessel					
Steam Generator--Direct Removal Costs					
Steam Generator--Cascading Costs					
RCS Piping					
Large Miscellaneous RCS Piping					
Small Miscellaneous RCS Piping					
RCS Insulation					
Pressurizer					
Pressurizer Relief Tank					
Primary Pumps					
Spent Fuel Racks					
Biological Shield					
Subtotal					
Decontamination and Dismantlement					
Decontamination of Site Buildings					
Removal of Contaminated Plant Systems					
Subtotal					
Management and Support					
Support Staff					
DOC Staff					
Consultant/Other Staff					
Termination Survey Costs					
Regulatory Costs					
Special Tools and Equipment					
Environmental Monitoring Costs					
Laundry Services					
Small Tools and Minor Equipment					
Nuclear Liability Insurance					
Property Taxes					
DOC Mobilization/Demobilization Costs					
Steam Generator--Undistributed Costs					
Chemical Decon					
Plant Power Usage					
Subtotal					
LLW Costs including packing,shipping and vendor/burial costs					
Total					

Table 6. Suggested Format for Tabulating BWR Decommissioning Costs by Period

Decommissioning Activity	Decommissioning Cost (Thousands of Estimate-Year Dollars)				
	Period 1 (X.X Years) Planning & Preparation	Period 2 (X.X Years) Plant Deactivation	Period 3 (X.X Years) Safe Storage Operations	Period 4 (X.X Years) Dismantle-ment	Duration (X.X Years) Total Cost
Radioactive Component Removal					
RPV Internals					
Reactor Pressure Vessel and Insulation					
Shielding					
Recirculation Pumps					
RCS Piping					
RCS Piping Insulation					
Main Turbine					
Main Turbine Condenser					
Moisture Separator Reheaters					
Feed Water Heaters					
Turbine Feed Pumps					
Structural Beams, Plates, & Cable Trays					
Spent Fuel Racks					
Subtotal					
Decontamination and Dismantlement					
Decontamination of Site Buildings					
Removal of Contaminated Plant Systems					
Subtotal					
Management and Support					
Support Staff					
DOC Staff					
Consultant/Other Staff					
Termination Survey Costs					
Regulatory Costs					
Special Tools and Equipment					
Environmental Monitoring Costs					
Laundry Services					
Small Tools and Minor Equipment					
Nuclear Liability Insurance					
DOC Mobilization/Demobilization Costs					
Chemical Decontamination					
Plant Power Usage					
Subtotal					
LLW Costs including packaging,shipping, and burial/vendor costs					
Total					

3.2 Cost Estimate for the Removal or Radiological Decontamination of Major Radioactive Components

For a PWR, major radiological components should include, but not be limited to, the following:

- reactor vessel and internals
- reactor coolant loops
- reactor coolant pumps
- bioshield
- pressurizer
- steam generators
- spent fuel racks
- other large contaminated components

For a BWR, major radiological components should include, but not be limited to, the following:

- reactor vessel and internals
- reactor coolant piping
- main turbines/generators
- turbine condensers
- moisture separator reheaters
- feedwater heaters
- feedwater pumps
- spent fuel racks
- other large contaminated components

3.3 Burial Cost and Volumes

The licensee should provide tabulations of expected waste volumes, packaging costs, shipping costs, and burial costs by decommissioning activity. Table 7 provides a suggested format. The licensee should also submit plans for radwaste disposition, including radwaste disposal sites to be used, if available. If a vendor will process the waste, the radwaste information after processing should be provided to show the results of the waste minimization. The licensee may also elect to provide descriptions of the methods and technologies used to achieve the improved waste characteristics. The licensee should also provide radwaste volumes by class expected to be generated during decommissioning. Table 8 provides a suggested format.

Table 7. Typical Waste Burial Cost and Volumes

Decommissioning Activity	Waste Volume (ft^3)	Packaging Cost (Estimate-Year $millions)	Shipping Cost (Estimate-Year $millions)	Burial Cost (Estimate-Year $millions)
Removal of Nuclear Steam Supply System				
Removal of Contaminated Plant Systems				
Radiological Decontamination of Site Buildings				
Dry Active Waste				
Total				

Table 8. Burial Volumes by Waste Class

Waste Class	Volume (ft^3)	Percent
Class A		
Class B&C		
Greater-Than-Class-C		
Total		

3.4 Other Items

The licensee should provide the following additional information:

- a brief discussion of contingency costs and the methods used to calculate them
- a brief discussion of how inflation is accounted for in the cost estimate
- a schedule for the accumulation and expenditure of decommissioning funds
- an estimate of the cost to support safe storage, if it becomes necessary
- labor requirements (person-years) and labor costs by time period; Table 9 provides a suggested format

Table 9. Labor Requirements and Labor Costs

	Labor Requirements (person-yrs) and Labor Costs (Estimate-Year $millions)									
	Phase 1		Phase 2		Phase 3		Phase 4		Total	
	(Labor Req)	(Labor Cost)	(Labor Req)	(Labor Cost)	(Labor Req)	(Labor Cost)	(Labor Req)	(Labor Cost)	(Labor Req)	(Labor Cost)
Decommissioning Crews										
Management/Support Staff										
Total										

4. LICENSE TERMINATION COST ESTIMATE

According to 10 CFR 50.82(a)(9)(ii)(F), a licensee must submit an "updated site-specific estimate of remaining decommissioning costs" as part of an LTP. According to 10 CFR 50.82(a)(9)(i), the licensee must submit the LTP at least 2 years before termination of the license. The estimated remaining costs of decommissioning must be compared with the present funds set aside for decommissioning. The financial assurance instrument required by 10 CFR 50.75 must be funded at least to the amount of the cost estimate. If there is a deficit in present funding, the LTP must indicate the means to ensure that adequate funds will be available to complete the decommissioning. Licensees should be aware that 10 CFR 50.82(a)(8)(i)(B) requires that expenditures are not to reduce the value of the decommissioning trust below an amount necessary to place and maintain the reactor in a safe storage condition if unforeseen conditions arise. Information on the preparation of an LTP may be found in Regulatory Guide 1.179, "Standard Format and Content of License Termination Plans for Nuclear Power Reactors" (Ref. 10), and NUREG-1700, "Standard Review Plan for Evaluating Nuclear Power Reactor License Termination Plans" (Ref. 11).

The cost estimate portion of the LTP is an updated version of the site-specific estimate that the licensee previously submitted to the NRC. The LTP cost estimate should contain refined estimates of the remaining decommissioning activities, including the cost to remediate surface and groundwater, soil contamination, waste transportation and disposal costs, and license termination survey costs. If the site is to be released for restricted use, the LTP cost estimate should also include estimated costs for controls and a description of the financial assurance mechanisms used to ensure the availability of funds when they are needed. Cost estimates for restricted release or entombment will be handled on a case-by-case basis.

5. FORMAT OF THE DECOMMISSIONING COST ESTIMATES

Graphic presentations such as charts, drawings, maps, diagrams, sketches, and tables should be employed when the information may be presented more adequately or conveniently by such means. Care should be taken to ensure that all information so presented is legible in the original documents and reproduced copies. Also, ensure that symbols are defined and scales are not reduced to the extent that visual aids are necessary to interpret items of information. These graphic presentations should be located in the section where the subject matter is primarily addressed. References should appear as footnotes on the page they were discussed or at the end of each chapter.

Decommissioning cost estimates may be submitted to the NRC in electronic or paper format, as described in Regulatory Issue Summary (RIS) 2001-05, "Guidance on Submitting Documents to the NRC by Electronic Information Exchange or on CD-ROM" (Ref.12).

5.1 Physical Format

5.1.1 Paper Size

- Text pages: 8½ × 11 inches.
- Drawings and graphics: 8½ × 11 inches. A larger size is acceptable provided the finished copy, when folded, does not exceed 8½ × 11 inches.

5.1.2 Paper Stock and Ink

Use suitable quality in substance, paper color, and ink density for handling and reproduction.

5.1.3 Page Margins

A margin of no less than 1 inch should be maintained on the top, bottom, and binding side of all pages submitted.

5.1.4 Printing

- Composition: Text pages should be single spaced.
- Type Face and Style: Should be suitable for image-copying equipment, including computer scanning.
- Reproduction: Copies may be mechanically or photographically reproduced.

5.1.5 Binding

No requirements.

5.1.6 Page Numbering

Pages should be numbered sequentially.

5.1.7 Procedures for Updating or Revising Pages

Data and text should be updated or revised by replacing pages. The changed or revised portion of each page should be highlighted by a "change indicator" mark consisting of a bold vertical line drawn in the margin opposite the binding margin. The line should be of the same length as the portion actually changed.

All pages submitted to update, revise, or add information to the report should show the date of change and a change or amendment number. A guide page listing the pages to be inserted and/or removed should accompany the revised pages. When major changes or additions are made, a revised table of contents should be provided.

5.1.8 Exceptions to Physical Specifications

Submittals may be made over the Internet or electronically; for guidance, see Regulatory Issue Summary 2001-05 (Ref. 12).

REFERENCES

1. U.S. Nuclear Regulatory Commission, "Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities," NUREG-0586, Supplement 1, October 2002.[1]

2. U.S. Nuclear Regulatory Commission, "Standard Format and Content for Post-Shutdown Decommissioning Activities Report," Regulatory Guide 1.185, August 2000.[2]

3. U.S. Department of Labor, Bureau of Labor Statistics, *Monthly Labor Review,* currently Table 24, updated periodically.

4. U.S. Department of Labor, Bureau of Labor Statistics, *Producer Price Index,* currently Table 6, updated periodically.

5. U.S. Nuclear Regulatory Commission, "Report on Waste Disposal Charges: Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities," NUREG-1307, Rev. 9, September 2000.[1]

6. R.I. Smith, G J. Konzek, and W.E. Kennedy, Jr., "Technology, Safety and Costs of Decommissioning a Reference Pressurized-Water Reactor Power Station," NUREG/CR-0130 (Prepared for the U.S. NRC by Pacific Northwest Laboratory, Richland, Washington), June 1978 (Addendum 1, July 1979; Addendum 2, July 1983; Addendum 3, September 1984; Addendum 4, July 1988).[1]

7. H.D. Oak et al., "Technology, Safety and Costs of Decommissioning a Reference Boiling-Water Reactor Power Station," NUREG/CR-0672 (Prepared for the U.S. NRC by Pacific Northwest Laboratory, Richland, Washington), June 1980 (Addendum 1, July 1983; Addendum 2, September 1984; Addendum 3, July 1988; Addendum 4, December 1990).[1]

8. G.J. Konzek et al., "Revised Analyses of Decommissioning for the Reference Pressurized-Water Reactor Power Station," NUREG/CR-5884 (Prepared for the U.S. NRC by Pacific Northwest Laboratory, Richland, Washington), November 1995.[1]

9. R.I. Smith et al., "Revised Analyses of Decommissioning for the Reference Boiling-Water Reactor Power Station," NUREG/CR-6174 (Prepared for the U.S. NRC by Pacific Northwest National Laboratory, Richland, Washington), July 1996.[1]

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[1] Copies are available at current rates from the U.S. Government Printing Office, P.O. Box 37082, Washington, DC 20402-9328 (telephone (202) 512-1800); or from the National Technical Information Service (NTIS) by writing NTIS at 5285 Port Royal Road, Springfield, VA 22161; http://www.ntis.gov; telephone (703) 487-4650. Copies are available for inspection or copying for a fee from the NRC's Public Document Room at 11555 Rockville Pike, Rockville, MD; the PDR's mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; email is PDR@nrc.gov.

[2] Single copies of regulatory guides, both active and draft, and draft NUREG documents may be obtained free of charge by writing the Reproduction and Distribution Services, USNRC, Washington, DC 20555-0001, or by fax to (301) 415-2289, or by email to DISTRIBUTION@nrc.gov. Active guides may also be purchased from the National Technical Information Service on a standing order basis. Details on this service may be obtained by writing NTIS, 5285 Port Royal Road, Springfield, VA 22161; telephone (703) 487-4650; online at http://www.ntis.gov. Copies of active and draft guides are available for inspection or copying for a fee from the NRC's Public Document Room at 11555 Rockville Pike, Rockville, MD; the PDR's mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; email PDR@nrc.gov.

10. U.S. Nuclear Regulatory Commission, "Standard Format and Content of License Termination Plans for Nuclear Power Reactors," Regulatory Guide 1.179, January 1999.[3]

11. U.S. Nuclear Regulatory Commission, "Standard Review Plan for Evaluating Nuclear Power Reactor License Termination Plans," NUREG-1700, April 2000.[4]

12. U.S. Nuclear Regulatory Commission, Regulatory Issue Summary 2001-05, "Guidance on Submitting Documents to the NRC by Electronic Information Exchange or on CD-ROM," January 25, 2001.[5]

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[3] Single copies of regulatory guides, both active and draft, and draft NUREG documents may be obtained free of charge by writing the Reproduction and Distribution Services, USNRC, Washington, DC 20555-0001, or by fax to (301) 415-2289, or by email to DISTRIBUTION@nrc.gov. Active guides may also be purchased from the National Technical Information Service on a standing order basis. Details on this service may be obtained by writing NTIS, 5285 Port Royal Road, Springfield, VA 22161; telephone (703) 487-4650; online at http://www.ntis.gov. Copies of active and draft guides are available for inspection or copying for a fee from the NRC's Public Document Room at 11555 Rockville Pike, Rockville, MD; the PDR's mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; email PDR@nrc.gov.

[4] Copies are available at current rates from the U.S. Government Printing Office, P.O. Box 37082, Washington, DC 20402-9328 (telephone (202) 512-1800); or from the National Technical Information Service (NTIS) by writing NTIS at 5285 Port Royal Road, Springfield, VA 22161; http://www.ntis.gov; telephone (703) 487-4650. Copies are available for inspection or copying for a fee from the NRC's Public Document Room at 11555 Rockville Pike, Rockville, MD; the PDR's mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; email is PDR@nrc.gov.

[5] The NRC's regulatory issue summaries are available electronically on the agency's public Web site at http://www.nrc.gov/reading-rm/doc-collections/gen-comm/reg-issues. Copies are also available for inspection or copying for a fee from the NRC's Public Document Room at 11555 Rockville Pike, Rockville, MD; the PDR's mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; email PDR@nrc.gov.

D. IMPLEMENTATION

The purpose of this section is to provide information to applicants and licensees regarding the NRC staff's plans for using this guide. No backfitting is intended or approved in connection with the issuance of this guide.

Except when an applicant or licensee proposes or has previously established an acceptable alternative method for complying with specified portions of the NRC's regulations, the methods described in this guide will be used in evaluating (1) submittals for licensing-basis documents, and (2) revisions or updates to the decommissioning cost estimates that are submitted in accordance with applicable regulations.

REGULATORY ANALYSIS

The NRC staff did not prepare a separate regulatory analysis for this regulatory guide. The regulatory analysis prepared for the amendments to 10 CFR Parts 2, 50, and 51, "Decommissioning of Nuclear Power Reactors," which the NRC issued on July 29, 1996 (61 FR 39278), provides the regulatory basis for this guide and examines the costs and benefits associated with implementing the rule as described in this guide. A copy of this regulatory analysis is available for inspection and copying (for a fee) at the NRC's Public Document Room (PDR), which is located at 11555 Rockville Pike, Rockville, Maryland. The PDR's mailing address is USNRC PDR, Washington, DC 20555-0001. The PDR can also be reached by telephone at (301) 415-4737 or (800) 397-4205, by fax at (301) 415-3548, and by email to PDR@nrc.gov.

BACKFIT ANALYSIS

This regulatory guide describes a voluntary method that the NRC staff considers acceptable for submitting the decommissioning cost estimates required by amendments to 10 CFR Parts 2, 50, and 51, "Decommissioning of Nuclear Power Reactors," which the NRC issued on July 29, 1996 (61 FR 39278). During the rulemaking process associated with those amendments, the NRC staff carefully considered the reasons for collecting the required information. Compliance with this regulatory guide is not a requirement, and a licensee may choose this or another method to achieve compliance with these rules. Thus, this regulatory guide does not require a backfit analysis, as described in 10 CFR 50.109(c), because it does not impose a new or amended provision in the NRC's rules, does not present a regulatory staff position that interprets the NRC's rules in a manner that is either new or different from a previous staff position; and does not require the modification of or addition to the systems, structures, components, or design of a facility, or the procedures or organization required to design, construct, or operate a facility.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE COMMISSION

In the matter of:	)	
ENTERGY NUCLEAR VERMONT YANKEE, LLC AND ENTERGY NUCLEAR OPERATIONS, INC.	)	Docket No. 50-271
(Vermont Yankee Nuclear Power Station)	)	

Reply of the Commonwealth of Massachusetts and the States of Connecticut and New Hampshire to NRC Staff's and Entergy's Answers to the Petition of the State of Vermont, the Vermont Yankee Nuclear Power Corporation, and Green Mountain Power Corporation for Review of Entergy Nuclear Operation, Inc.'s Planned Use of the Vermont Yankee Nuclear Decommissioning Trust Fund

Submitted: December 17, 2015

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INTRODUCTION

The Commonwealth of Massachusetts and the States of Connecticut and New Hampshire (collectively, "the States") submit, pursuant to the Secretary's November 10, 2015 Order, this Reply to respond to Answers submitted by both the Nuclear Regulatory Commission Staff (NRC Staff) and Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (collectively, "Entergy") to the November 4, 2015 Petition of the State of Vermont, the Vermont Yankee Nuclear Power Corporation, and the Green Mountain Power Corporation (collectively, "Petitioners") for Review of Entergy Nuclear Operations, Inc.'s Planned Use of the Vermont Yankee Nuclear Decommissioning Trust Fund (Petition).[1] While the Petition was filed to address issues at Vermont Yankee, it raises serious, never before adjudicated questions about the use of decommissioning trust funds that apply to every such fund in the nation, including the funds for Entergy's Pilgrim Nuclear Power Station (Pilgrim) in Plymouth, Massachusetts, and the James A. FitzPatrick Nuclear Power Plant (FitzPatrick) in Scriba, New York—both of which are now slated for closure between 2016 and 2019. A decision to delay the resolution of these questions or, worse, a decision to adopt the NRC Staff's and Entergy's positions, would threaten to undermine nuclear plant owners' ability to remediate the radiological contamination at plants that have ceased operations and shift the burden of doing so to the States' taxpayers. For that reason, the Commission must exercise its general supervisory authority to address these issues now.

[1] Because this is not a formal proceeding and because the Secretary's November 10, 2015 Order did not limit the persons who may file a reply in response to the Order (referring instead to "any answers" and "any reply to an answer"), the States, having serious concerns about how the positions NRC Staff and Entergy asserted in their Answers may affect the States' distinct interests, file this timely Reply to address them. In the alternative, the States respectfully request that the Commission treat this filing as an amicus brief in support of Petitioners.

The States support the Petition. The interests of the States—two of which lie on Vermont's border in very close proximity to Vermont Yankee and all three of which lie on the Connecticut River downstream of Vermont Yankee—are aligned with Vermont's interests, because they could be directly harmed if Vermont Yankee is not decontaminated and would be directly harmed if the decommissioning trust funds for the plants in their states are insufficient to complete the decommissioning process. The States also have a unique interest, which they seek to ensure is recognized and considered in the Commission's deliberations on the issues set forth in the Petition. Unlike Vermont, each of the States joining this Reply has an operational nuclear power plant located within its borders.[2] Each of those plants thus has the ability to take steps now to (1) transfer spent fuel into dry casks as soon as the spent fuel is ready for transfer rather than delaying that work until the plants cease operations[3] and (2) plan for the payment of *non*-decommissioning activities after the plants cease operations and before the plants are radiologically decontaminated. By doing so, these plants can ensure that their decommissioning trust funds will be used solely to pay for legitimate decommissioning activities until the radiological decommissioning work is complete, as longstanding NRC regulations mandate. *See infra* pp.3-8.[4]

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[2] *E.g.*, Pilgrim Nuclear Power Plant, Plymouth, Mass.; Millstone Nuclear Power Plant, Unit 3, Waterford, Conn.; Seabrook Nuclear Power Plant, Seabrook, N.H.

[3] As the NRC has made clear, spent fuel management costs are considered "operational" costs and are costs that NRC requires plants to account for apart from their decommissioning trust fund assets. *See* General Requirements for Decommissioning Nuclear Facilities, 53 Fed. Reg. 24,018, 24,019 (June 27, 1988); *see also* 10 C.F.R. § 50.54(bb) (2015).

[4] To be clear, the States do not object to the use of decommissioning trust funds that remain after the radiological contamination is eliminated. In addition, as explained below, they also do not object to the pre-radiological decontamination use of funds that were collected to perform non-decommissioning activities as long as the use of those funds complies with the NRC's longstanding guidance. *See infra* pp.7-8 n.15.

This is a particularly pertinent concern for those plants within Entergy's fleet that have recently announced that they will close (e.g., Pilgrim and FitzPatrick).[5] For those plants, there will be increasing pressure on the NRC to permit the use of decommissioning trust funds for purposes more broadly related to site restoration and spent fuel waste management and storage—purposes that clearly do not constitute decommissioning as the NRC has defined that term. Unfortunately, the NRC's overly lenient approach to allowing, either affirmatively or through acquiescence, plant owners to draw on their decommissioning trust funds to pay for non-decommissioning expenses before the decommissioning work is complete has created an untoward incentive for those plants not to plan for the payment of non-decommissioning expenses while they are in operation, and instead to wait until the decommissioning trust fund is the only asset directly available to them. The NRC's approach is inconsistent with its own regulations and threatens both the environment and public health and safety.

ARGUMENT

I. NRC'S REGULATIONS DICTATE THAT TO PROVIDE ADEQUATE ASSURANCE OF PUBLIC HEALTH AND SAFETY NUCLEAR POWER FACILITY OWNERS MUST RESERVE DECOMMISSIONING TRUST FUNDS SOLELY FOR "DECOMMISSIONING" UNTIL A SITE IS RADIOLOGICALLY DECONTAMINATED.

Decommissioning trust funds are the means by which the NRC complies with its Atomic Energy Act (AEA) obligations to ensure that a licensee has the financial means to decontaminate its site and "provide adequate protection to the health and safety of the public." 42 U.S.C. §§ 2201(x)(1), 2232(a). Consistent with these obligations, in 1981, the NRC emphasized that a

[5] In Massachusetts, for example, State legislators are so concerned about the sufficiency of Pilgrim's decommissioning trust fund that they have introduced a bill that would require any nuclear power plant in Massachusetts to pay annually $25 million into a state post-closure fund. *See An Act establishing funding to provide moneys for postclosure activities at nuclear power stations*, Sen. Doc. No. 1798 (Jan. 12, 2015), *available at* https://malegislature.gov/Bills/189/Senate/S1798 (last visited Dec. 17, 2015).

"*high degree* of assurance is required from the nuclear facility licensee that adequate funds are available to decommission the facility" so that the agency can comply with its "responsibility to protect public health and safety." Decommissioning Criteria for Nuclear Facilities; Notice of Availability of Draft Generic Environment Impact Statement, 46 Fed. Reg. 11,666, 11,667 (Feb. 10, 1981) (emphasis added). The NRC then explained that "[c]ompleting decommissioning and releasing the facility for unrestricted use eliminates potential problems of increased numbers of sites used for the confinement of radiological materials, as well as potential health, safety, regulatory and economic problems associated with maintaining the site." *Id.* To better comply with this obligation, the NRC embarked on a ten year rulemaking effort to establish technical and financial criteria for decommissioning licensed facilities that serve as the foundation for today's regulatory structure for decommissioning and decommissioning trust funds.[6]

One of the most fundamental decisions that the NRC made in its early efforts to ensure a "high degree" of financial assurance for decommissioning facilities was to define narrowly the term "decommission." In the 1988 Final Rule, the Commission defined that term to mean "to remove (as a facility) safely from service and to reduce the residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license." 53 Fed. Reg. at 24,049 (codified at 10 C.F.R. § 50.2 (1989)).[7] There, the NRC also expressly identified

[6] General Requirements for Decommissioning Nuclear Facilities, 53 Fed. Reg. 24,018 (June 27, 1988); Decommissioning Criteria for Nuclear Facilities, 50 Fed. Reg. 5,600 (proposed Feb. 11, 1985); Decommissioning Criteria for Nuclear Facilities; Notice of Availability of Draft Generic Environment Impact Statement, 46 Fed. Reg. 11,666 (Feb. 10, 1981); Decommissioning Criteria for Nuclear Facilities, 43 Fed. Reg. 10,370 (advanced notice of proposed rulemaking Mar. 13, 1978).

[7] The current definition of "decommission" is not materially different from the original 1988 definition, and reads: "*[d]ecommission* means to remove a facility or site safely from service and reduce residual radioactivity to a level that permits—(1) Release of the property for unrestricted use and termination of the license; or (2) Release of the property under restricted conditions and termination of the license." 10 C.F.R. § 50.2 (2015).

activities that do not constitute decommissioning: "removal and disposal of spent fuel," "removal and disposal of nonradioactive structures," and [d]isposal of nonradioactive hazardous waste." *Id.* at 24,019; *see also id*. at 24,028 (explaining that the Pacific Northwest Laboratory's cost estimate did "not include the cost of demolition and removal of noncontaminated structures, storage and shipment of spent fuel, or restoration of the site"), 24,031 (same); 10 C.F.R. § 50.75(c) & n.1 (2015) (codifying list).[8] Subsequent NRC statements have all confirmed that facility owners are allowed to use decommissioning trust funds solely for activities that reduce radiological contamination, not expenses like spent fuel management, removal of nonradioactive structures, disposal of nonradioactive hazardous waste, property taxes, insurance, or attorneys' fees.[9] In light of the definition's plain meaning and NRC's clear statements, Entergy's reliance

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[8] The exclusion for the costs associated with the removal and disposal of spent fuel also includes the costs to manage the spent fuel while it is stored on site. *E.g.*, *In re Entergy Nuclear Vermont Yankee, LLC & Entergy Nuclear Operations, Inc.*, Dkt. No. 50-271-LA-3, LBP-15-24, at 4, 82 NRC __ (Aug. 31, 2015) ("*In re Entergy I*, LBP-15-24, at __"); *see also* 10 C.F.R. § 50.54(bb) (requiring licensees to submit a plan detailing how they will manage and fund post-closure management of spent fuel "until title . . . and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository.").

[9] *See* NRC Regulatory Guide 1.184, Decommissioning of Nuclear Power Reactors, Rev. 1, at 6 (Oct. 2013) (Agencywide Documents Access and Management System (ADAMS) Accession No. ML13144A840) (listing the activities that do not qualify for use of Decommissioning Trust Funds); Decommissioning Trust Provisions, 67 Fed. Reg. 78,332, 78,340 (Dec. 24, 2002) (distinguishing between radiological and non-radiological decommissioning costs); Decommissioning Trust Provisions, 66 Fed. Reg. 29,244, 29,246 (proposed May 30, 2001) ("the decommissioning trust fund is reserved for decommissioning"); Mem. from William D. Travers, Exec. Dir. for Operations, NRC, to The Commissioners, Subj: Summary of Decommissioning Fund Status Reports (SECY-99-170) (Jul. 1, 1999), *available at* http://www.nrc.gov/reading-rm/doc-collections/commission/secys/1999/ secy1999-170/1999-170scy.html (last visited Dec. 17, 2015) ("Decommissioning Fund Status Reports Mem.") (stating that "the NRC specifically excludes" from the 10 C.F.R. § 50.2 decommissioning definition "costs of spent fuel management, demolition of non-radiological structures, and site restoration"); Decommissioning of Nuclear Power Reactors, 61 Fed. Reg. 39,278, 39,285 (July 29, 1996) ("Radiological activities that go beyond the scope of decommissioning, as defined in § 50.2, such as waste generated during operations or demolition costs for 'greenfield' restoration, are not appropriate costs . . . ."); Use of Decommissioning Trust Funds Before Decommissioning

on NUREG/CR-5884,[10] a report prepared by a private contractor on behalf of the NRC, to attempt to broaden the category of activities that fall within the plain meaning of the definition of "decommissioning" is misplaced. *See* Entergy Answer at 20-21.[11]

NRC's regulations make clear that decommissioning trust funds are "restricted to decommissioning expenses . . . until after decommissioning has been completed." 10 C.F.R. § 50.75(h)(1)(iv) (2015); *see also id.* at § 50.82(a)(8)(i)(A) (2015). Yet, despite this clear directive and the Commission's prior statements on the need for a high degree of assurance that funds will be available to decommission facilities, the NRC has, as NRC Staff emphasize, routinely granted exemptions from the NRC's regulations that allow facility owners to use decommissioning trust funds for spent fuel management,[12] and has, as Entergy highlights, otherwise tacitly approved decommissioning trust fund use for purposes that clearly do not

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Plan Approval; Draft Policy Statement, 59 Fed. Reg. 5216, 5217 (Feb. 3, 1994) (stating that ensuring that withdrawals are for "legitimate decommissioning activities as defined in 10 CFR 50.2 . . . would prevent funds from being used for activities that do not reduce radioactivity at the site").

[10] NUREG/CR-5884, Revised Analyses of Decommissioning for the Reference Pressurized Water Reactor Power Station (Nov. 1995) (ADAMS Accession No. ML14008A187).

[11] Notably, NRC Staff does not resort to this misplaced authority in their Answer. *See* NRC Staff Answer 1 - 69. Moreover, while Entergy argues that NUREG/CR-5884 is "entitled to special weight," *see* Entergy Answer at 20 n.89, that document was, again, prepared by a contractor and thus does not constitute NRC's own view of the meaning of the term decommission. And even if it were considered both an interpretation of that term *and* the NRC's own interpretation of it, an agency interpretation that is inconsistent with its regulation, as would be the case here, is not entitled to any weight at all. *See League of Wilderness Defenders/Blue Mtns. Biodiversity Project v. Forsgren*, 309 F.3d 1181, 1189 (9th Cir. 2002) (refusing to give any weight to two opinion letters because they lacked "the power to persuade"); *see also Auer v. Robbins*, 519 U.S. 452, 461 (1997) (holding that formal agency interpretation of its own regulations is entitled to no weight if it is "inconsistent with the regulation.").

[12] NRC Staff Answer at 24-25 & nn.113 & 114.

constitute legitimate decommissioning expenses.[13] In other words, the narrow exception has become the de facto rule despite the NRC's prior expressed concerns about the need to jealously protect decommissioning trust funds for their intended purpose until that purpose is achieved—concerns that are all the more real in a de-regulated world and when a plant is placed in "safe storage" and decontaminated within a sixty year period (e.g., SAFSTOR, *see* 53 Fed. Reg. at 24,021 (defining term)). Indeed, the Commission has recognized that the latter two issues necessitate increased funding assurance, because (1) de-regulated plants cannot collect decommissioning funds from ratepayers and will not generate any new revenue once they cease operations, and (2) it is impossible to predict all of the contingencies that could occur during a sixty-year period and how those contingencies will affect decommissioning costs.[14]

The NRC Staff claim that none of the issues raised in the Petition warrant Commission review because they are not "novel," *see* NRC Answer at 24, but the fact that the NRC repeatedly has followed a path that is both inconsistent with its regulations and its own prior expressed conservativism regarding fund use makes it even more critical for the Commission to review them now.[15] A mistake, of course, cannot be made right through mere repetition; instead,

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[13] Entergy Answer at 22 & n.100.

[14] In 1996, for example, the NRC wrote that "with electric utility deregulation becoming more likely, it may need to require *additional* decommissioning funding assurance for those licensees that are no longer able to collect full decommissioning costs in rates or set their own rates." 61 Fed. Reg. at 39,285 (emphasis added). In a similar vein, in 1988, the NRC noted, quite correctly, that there is "as great or greater need for assurance of funds over the extended timeframe involved with a facility in SAFSTOR when the facility is no longer a revenue producing asset." 53 Fed. Reg. at 24,034.

[15] For its part, Entergy argues that the fact that the decommissioning funds its predecessor collected from ratepayers included the cost to pay for property taxes, insurance, emergency planning fees, spent fuel management, and non-radiological decontamination costs demonstrates that all of those costs qualify as decommissioning costs. Entergy Answer at 23 n.101. That is wrong, however. In addressing this issue in 2002, the Commission explicitly acknowledged that State utility regulators had either allowed or required facilities to collect funds that went beyond

a mistake's repetition makes it all the more urgent to remedy. And even if that were not reason enough, an Atomic Safety Licensing Board (ASLB) Panel recently noted "that neither the Commission nor any licensing board has had the opportunity to interpret the meaning of 10 C.F.R. § 50.75(h)(5), and that there exists a genuine dispute over what costs constitute legitimate decommissioning expenses.[16] In short, and as Petitioners correctly warn, the NRC's lenient approach to plant owner use of decommissioning funds for virtually any expense following cessation of power generation and before the completion of radiological decontamination has created a dangerous incentive for plant owners to plan to rely exclusively on their decommission trust funds to cover those expenses. *See* Petition at 42. That incentive puts public health and State taxpayers at risk and these issues thus require Commission consideration and action now.

II. NRC MUST ENSURE THAT NUCLEAR FACILITY OWNERS DISCLOSE ALL EXPENSES FOR WHICH THEY SEEK TO WITHDRAW MONEY FROM DECOMMISSIONING TRUST FUNDS PRIOR TO THE WITHDRAWAL AND MAKE THAT INFORMATION AVAILABLE TO THE PUBLIC TO PREVENT MISUSE OF THOSE FUNDS.

The NRC must ensure that nuclear facility owners disclose all expenses for which they seek to use decommissioning trust funds to prevent continued misuse of those funds and the serious implications that misuse poses for the environment and public health and safety. As the U.S. Court of Appeals for the Seventh Circuit has recognized, the NRC is "the designated policeman of decommissioners," and in that role it has the authority to address "every potential

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the NRC's definition of decommission, concluded that those funds could be co-mingled with radiological decommissioning funds, and required, in those instances, facilities to create separate sub-accounts "so funds for each type of activity are appropriately identified." 67 Fed. Reg. at 78,339-40. These funds can appropriately be used by plant owners to pay for non-decommissioning costs prior to the completion of radiological contamination and the States do not take issue with this process as long as the plant owners account specifically for the use of these funds.

[16] *In re Entergy I*, LBP-15-24, at 43; *see also In re Entergy Nuclear Vermont Yankee, LLC & Entergy Nuclear Operations, Inc.*, Dkt. No. 50-271-LA-3, LBP-15-28, at 11, 82 NRC __ (Oct. 15, 2015) ("*In re Entergy II,* LBP-15-28, at __").

malfeasance or misfeasance of assets dedicated to the decommissioning process." *Pennington v. ZionSolutions LLC*, 742 F.3d 715, 719 (7th Cir. 2014). The NRC cannot perform that role properly, however, unless nuclear facility owners disclose the details of the expenses they seek to pay for with decommissioning trust fund assets *before* the withdrawal occurs. As explained more fully below, pre-disbursement notice is especially important for merchant reactor nuclear plants like Vermont Yankee and Pilgrim because they do not have direct access to any other source of funds once they cease operations and it would thus be complicated for NRC to remedy an inappropriate withdrawal *after* it occurs. *See* 53 Fed. Reg. at 24,034.

The risks associated with plants that do not have direct access to funds after they close is exacerbated by the manner in which some companies have organized their corporate structures and associated assets. By separating the parent entity's assets from the plants themselves, these companies have complicated the NRC's ability to reach the parent entity's assets to remedy an unlawful decommissioning trust fund withdrawal or any trust-fund shortfall to ensure completion of the decommissioning process without the expenditure of public funds. Entergy, for example, has created a complex corporate structure in which one company, Entergy Holding Companies, LLC, holds the licenses to operate Entergy's merchant plants but does not also own the plants, and separate limited liability companies hold the licenses to possess the plants.[17] And all of those entities are then themselves separated from the parent entity—Entergy Corporation.[18] In

[17] *See* Ltr. from John J. Sipos, Assistant Attorney General, New York Attorney General's Office, to Eric J. Leeds, Director, Office of Nuclear Reactor Regulation, Nuclear Regulatory Commission. re Dockets 50-333, 50-271, and 50-293 NRC Enforcement Proceeding No. 2013-0192, at 3-7 (Dec. 2, 2013 (corrected)) (ADAMS Accession No. ML15027A458) (explaining each entities role and providing a diagram of the structure).

[18] *See* State of New York Comments on Proposed Decision, NRC Dkt. Nos. 50-333, 50-293, 50-271, at 13 (Apr. 27, 2015) (ADAMS Accession No. ML15268A260) (providing diagram of Entergy's corporate structure).

this way, Entergy has attempted to shield the assets of its parent and affiliated entities from the potential liabilities associated with the limited liability companies that either own or operate its merchant reactors. Thus, if neither the NRC nor a State receives notice of a proposed inappropriate decommissioning trust fund withdrawal before the withdrawal occurs, it would unnecessarily complicate efforts to force the licensee to repay those funds into the trust because *its* only source of funds would be the trust. Or, even worse, if the limited liability company holding the license to possess the plant were to claim lack of funds, that claim would also complicate efforts to force the parent entity to fill that void. While the NRC Staff have argued that the NRC will "pursue Entergy" if there is a funding shortfall, it has not explained how it would do so and it has said nothing at all as to how it would remedy an unlawful withdrawal from a decommissioning trust fund. *See* NRC Staff Answer at 44.

In prior statements, the NRC has itself emphasized the importance of receiving pre-decommissioning trust fund disbursement notices. In 2002, for example, the Commission concluded "[w]ith respect to . . . 30-day notification for disbursements" that it "needs to have this information in a timely fashion . . . to effectively monitor licensees, especially when a licensee is not in decommissioning under the PSDAR or an approved license termination plan." 67 Fed. Reg. at 78,335-36. And, in an earlier 1999 Memorandum to the Commissioners, the NRC's Director of Operations stated that the NRC needs "to require more direct NRC oversight over the decommissioning trust funds" at non-rate regulated facilities, like Pilgrim.[19] There, the Staff noted that it required the decommissioning trusts for two facilities, including Pilgrim, to be modified to include language that, *inter alia*, required the facility owners to "provide 30-day notice to the NRC of disbursements from the trusts and prohibit trust fund disbursements if the

[19] Decommissioning Fund Status Reports Mem., *supra* note 9, at 3.

Director of NRR objects."[20] In short, the Commission needs detailed, pre-disbursement notifications so that it can perform its regulatory functions and ensure that decommissioning of all licensed facilities will be accomplished in a safe and timely manner.

The ASLB Panel's recent Memorandum and Order in *In re Entergy I*, LBP-15-24 granting Vermont's request for a hearing on two contentions and the Panel's later Order in *In re Entergy II*, LBP-15-28 allowing a conditional withdrawal of Entergy's license amendment request (LAR) in that proceeding highlight the necessity of pre-disbursement notices and the need for the Commission to address the issues raised in the Petition now. After the Panel granted Vermont's request for a hearing on "the necessity of a 30-day notice requirement in light of the specific factual issues that Vermont's petition allege[d] will reduce the fund to such an extent that the plant cannot be maintained in a safe condition," *In re Entergy I*, LBP-15-24, at 28-29; *see also In re Entergy II*, LBP-15-28, at 2 (defining issue), Entergy, supported by NRC Staff, asked to withdraw its LAR to avoid resolution of this issue. Despite the Panel's conclusion that an actual dispute existed over the Entergy's use of the Vermont Decommissioning Trust Fund and the importance of the 30-day notices to the NRC's and Vermont's efforts to evaluate those uses, remarkably, Entergy opted to provide even *less* information in its next thirty (30) day withdrawal notice to the NRC. *In re Entergy II*, LBP-15-28, at 9. In partial response to that fact, the Panel agreed to require Entergy to disclose details about six specific line items in its future 30-day notices so that those withdrawals can be "policed." *Id.* at 11-12.[21]

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[20] *Id.*

[21] Those specific items are six line items in the Vermont Yankee Post Shutdown Decommissioning Activities Report (PSDAR) and the legal costs associated with an earlier proceeding. *In re Entergy II*, LBP-15-28, at 11. The six line items are: "(1) a $5 million payment to Vermont as part of a settlement agreement; (2) emergency preparedness costs; (3) shipments of non-radiological asbestos waste; (4) insurance; (5) property taxes; and

All of this makes clear that the submission of detailed pre-decommissioning trust fund disbursement notices is necessary for the NRC to execute its obligations under AEA and existing regulations. In those instances where the licensee has an existing obligation to provide 30-day pre-disbursement notice, NRC staff should oppose any effort by the licensee to seek to eliminate that obligation through a LAR or by simply failing to comply with its existing trust agreement. But, in light of the NRC Staff's apparent acquiescence in facility owners' historically improper interpretation of what constitute legitimate decommissioning expenses, *supra* pp.6-7,[22] the Commission must also ensure that the pre-disbursement notices detail all proposed expenses and make those notices readily available to States and the public. Public transparency is, after all, the hallmark of the most successful regulatory programs in the United States. Given the critical importance of the decommissioning trust funds to the achievement of radiological decontamination and the relationship of the success of that requirement to the environment and public health and safety and State treasuries, States and the public have a right to know whether those funds are being used lawfully for their intended purpose, and to call on the NRC to take action when they are being misused.

III. IF THE NRC ALLOWS NUCLEAR PLANT OWNERS TO USE DECOMMISSIONING TRUST FUNDS FOR NON-DECOMMISSIONING PURPOSES PRIOR TO COMPLETE RADIOLOGICAL DECONTAMINATION, THE NRC MUST COMPLETE A NEPA COMPLIANT-REVIEW OF THE POTENTIAL ENVIRONMENTAL CONSEQUENCES OF THAT DECISION.

The National Environmental Policy Act (NEPA), 42 U.S.C. §§ 4321-4347, is "our basic national charter for protection of the environment." 40 C.F.R. § 1500.1(a) (2015). The Act has

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(6) replacement of structures related to dry cask storage, such as a bituminous roof." *Id.* (citation omitted).

[22] *See also In re Entergy I*, LBP-15-24, at 5 n.24 (noting that it is "curious that NRC Staff would approve a request to exempt a licensee from regulations which do not apply to the licensee" and that "[i]t is even more curious that the NRC Staff purports to make such an exemption effective immediately.").

two purposes. *United States v. Coalition for Buzzards Bay*, 644 F.3d 26, 31 (1st Cir. 2011). "First, it 'places upon an agency the obligation to consider every significant aspect of the environmental impact of a proposed action." *Baltimore Gas & Electric v. NRDC*, 462 U.S. 87, 97 (1983) (citation omitted). "Second, it ensures that the agency will inform the public that it has indeed considered environmental concerns in its decisionmaking process." *Id.* (citation omitted). To achieve these purposes, NEPA "demands that a decisionmaker" take "a hard look" at "all significant environmental impacts before choosing a course of action," *Sierra Club v. Marsh*, 872 F.2d 497, 502 (1st Cir. 1989). While the Act does not dictate particular results, its procedures are intended to "affect the agency's substantive decision." *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 350 (1989).

The NRC Staff has determined not to comply with the Commission's NEPA obligations, including the obligation to consider potential cumulative impacts, both in the context of its decision to exempt Entergy's Vermont Yankee plant from certain decommissioning regulations and more generally from the issues raised by the Petition in its Answer here. Both Entergy and NRC Staff point to the 2002 *Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* (NUREG-0586, Supplement 1) (Decommissioning GEIS) to support their positions. NRC Staff Answer at 56; Entergy Answer at 12, 37.[23] Neither Entergy nor the NRC Staff acknowledges, however, that the Decommissioning GEIS did not consider the potential environmental consequences of the costs of non-decommissioning activities, such as spent fuel management, or of withdrawing funds from decommissioning trust funds to pay for those costs. Indeed, the NRC states in the Decommissioning GEIS that "issues related to spent fuel

[23] *Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* (NUREG-0586, Supplement 1) (Nov. 2002) (ADAMS Accession Nos. ML023470304, ML023470323, ML023500187, ML023500211, and ML023500223).

maintenance and storage (including costs) are outside the scope of this Supplement." Decommissioning GEIS at App. O-101 (ADAMS Accession No. ML023500211). Moreover, the ASLB effectively rebuffed NRC Staff's and Entergy's arguments on this point, concluding that "Vermont's factual allegations and documentary support" demonstrate "a genuine dispute concerning the completeness and correctness of the LAR and whether the LAR will ensure adequate protection of public health and safety." *In re Entergy I*, LBP-15-24, at 28.

Finally, it is undisputed that a decommissioning trust fund shortfall may pose significant environmental and public health and safety consequences. *See generally*, *e.g.*, 53 Fed. Reg. at 24,033. Yet, despite this real world consequence, NRC Staff have treated Entergy's exemption and LAR requests, which explicitly and implicitly allow Entergy to withdraw funds from the Vermont Yankee decommissioning trust fund for non-decommissioning activities, as mere administrative matters and without consideration of previously unforeseen consequences. For example, as the ASLB also noted, with some NRC Staff concurrence, Vermont Yankee's PSDAR "assumes that the Department of Energy 'will begin to take irradiated fuel from [the plant] by 2026, [and] that all irradiated fuel will be eliminated from the Vermont Yankee site by 2052,'" but, in reality, "the *indefinite* storage of spent fuel on-site is a very possible outcome, as demonstrated by the assumptions underlying the Continued Storage Rule." *In re Entergy I*, LBP-15-24, at 28 (emphasis added). And the exemption Entergy obtained to use decommissioning trust funds to manage spent fuel is hardly a matter of idle curiosity, since it plans to withdraw $225 million from the fund—over a third of the current amount in the Vermont Yankee decommissioning trust fund—to cover spent fuel management costs. *Id.* at 39 & n.208. Far from requiring no environmental review at all, *see* NRC Staff Answer at 53-54, decisions that threaten to impair the long-term viability of the Vermont Yankee decommissioning trust fund (or

any other decommissioning trust fund) demand that the NRC take the "hard look" at all of the potential environmental consequences, including the cumulative impacts, that NEPA requires so that both the Commission and the public may be fully informed before the NRC makes its decision.

CONCLUSION

For the foregoing reasons, the States respectfully request that the Commission grant the relief Vermont has requested in its Petition, *see* Petition at 59-60, and to grant the States party status to appear and present their views on the issues raised by the Petition and in this Reply.

Dated: December 17, 2015

Respectfully submitted,

Executed in Accord with 10 C.F.R. § 2.304(d)

THE COMMONWEALTH OF MASSACHUSETTS

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE COMMISSION

	)	
In the matter of:	)	
	)	
ENTERGY NUCLEAR VERMONT YANKEE, LLC	)	Docket No. 50-271
AND ENTERGY NUCLEAR OPERATIONS, INC.	)	
	)	
(Vermont Yankee Nuclear Power Station)	)	
	)	

CERTIFICATE OF SERVICE

Pursuant to 10 C.F.R. § 2.305, I certify that, on this date, a copy of the foregoing "Reply of the Commonwealth of Massachusetts and the States of Connecticut and New Hampshire to NRC Staff's and Entergy's Answers to Petition of the State of Vermont, the Vermont Yankee Nuclear Power Corporation, and Green Mountain Power Corporation for Review of Entergy Nuclear Operation, Inc.'s Planned Use of the Vermont Yankee Nuclear Decommissioning Trust Fund" was served upon the Electronic Information Exchange (the NRC's E-Filing System), in the above captioned docket.

/ Signed (electronically) by/

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Dated: December 17, 2015

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[7590-01-P]

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
Entergy Nuclear Vermont Yankee, LLC	)	
Entergy Nuclear Operations, Inc.	)	Docket Nos.: 50-271 and 72-59
	)	License No.: DPR-28
Vermont Yankee Nuclear Power Station	)	
	)	

ORDER APPROVING THE TRANSFER OF LICENSE
AND CONFORMING AMENDMENT

I.

Entergy Nuclear Operations, Inc. (ENOI), on behalf of itself and Entergy Nuclear Vermont Yankee, LLC (ENVY), are the holders of Renewed Facility Operating License No. DPR-28, which authorizes the operation of the Vermont Yankee Nuclear Power Station (VY), and the general license for the VY Independent Spent Fuel Storage Installation (ISFSI). VY permanently ceased operations on December 29, 2014. Pursuant to Sections 50.82(a)(1)(i) and (a)(1)(ii) of Title 10 of the *Code of Federal Regulations* (10 CFR), by letter dated January 12, 2015, ENOI certified to the NRC that it had permanently ceased operations at VY and that all fuel had been permanently removed from the reactor. Therefore, pursuant to 10 CFR 50.82(a)(2), operations at VY are no longer authorized under the 10 CFR Part 50 license, and ENOI and ENVY are licensed to possess, but not use or operate, VY under Renewed Facility Operating License No. DPR-28, subject to the conditions specified therein. The VY site is located in the town of Vernon, Vermont, in Windham County on the west shore of the Connecticut River immediately upstream of the Vernon Hydroelectric Station.

Enclosure 1

II.

By letter dated February 9, 2017 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML17045A140), and as supplemented by letters dated April 6, 2017 (ADAMS Accession No. ML17096A394), August 22, 2017 (ADAMS Accession No. ML17234A141), August 28, 2017 (ADAMS Accession No. ML17248A468), December 4, 2017 (ADAMS Accession No. ML17339A896), December 22, 2017 (ADAMS Accession No. ML18009A459), May 21, 2018 (ADAMS Accession No. ML18143B484), and June 28, 2018 (ADAMS Accession No. ML18183A220), ENOI, on behalf of itself and ENVY, and NorthStar Nuclear Decommissioning Company, LLC (NorthStar NDC) (together, the Applicants), requested that the U.S. Nuclear Regulatory Commission (NRC) consent to the proposed direct and indirect transfer of the VY Renewed Facility Operating License No. DPR-28 and the general license for the VY ISFSI (collectively referred to as the facility). Specifically, the Applicants requested that the NRC consent to the direct transfer of ENOI's currently licensed authority (licensed operator for decommissioning) to NorthStar NDC. In addition, the Applicants requested the indirect transfer of control of ENVY's ownership interests in the facility licenses to NorthStar Decommissioning Holdings, LLC, and its parents NorthStar Group Services, Inc. (NorthStar), LVI Parent Corp. (LVI) and NorthStar Group Holdings, LLC (Holdings). These direct and indirect transfer requests are submitted to the NRC for approval pursuant to Section 184 of the Atomic Energy Act of 1954, as amended (AEA), "Inalienability of Licenses," and 10 CFR 50.80, "Transfer of licenses," 10 CFR 72.50, "Transfer of licenses," and 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit." The supplemental information letters, listed above, contained clarifying information, did not expand the application beyond the scope of the original notice, and did not affect the applicability of the NRC's no significant hazards consideration determination.

ENOI and ENVY intend to transfer the licensed possession, maintenance, and decommissioning authorities to NorthStar NDC in order to implement expedited decommissioning at VY. Following approval and implementation of the proposed direct transfer of control of the license, NorthStar NDC would assume licensed responsibility for VY through the direct transfer of ENOI's responsibility for licensed activities at VY to NorthStar NDC. If the proposed indirect transfer of control is approved, ENVY would change its name to NorthStar VY, but the same legal entity would continue to exist before and after the proposed transfer. NorthStar VY would also enter into an operating agreement with NorthStar NDC, which provides for NorthStar NDC to act as NorthStar VY's agent and for NorthStar VY to pay NorthStar NDC's costs of operation, including all decommissioning costs. NorthStar VY would own the VY facility as well as its associated assets and real estate, including its nuclear decommissioning trust fund, title to spent nuclear fuel, and rights pursuant to the terms of its Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the U.S. Department of Energy. Certain off-site assets and real estate of ENVY are excluded, such as administrative offices and off-site training facilities. Upon the proposed license transfer, NorthStar NDC would assume responsibility for compliance with the current licensing basis, including regulatory commitments that exist at the closing of the transaction between the Applicants, and would implement any changes under applicable regulatory requirements and practices. The Applicants also requested that the NRC approve a conforming administrative amendment to the facility license to reflect the proposed direct transfer of the license from ENOI to NorthStar NDC as well as a planned name change for ENVY from ENVY to NorthStar VY.

Notice of NRC consideration of the license transfer application was published in the *Federal Register* (*FR*) on May 24, 2017 (82 *FR* 23845) and included an opportunity to comment, request a hearing, and petition for leave to intervene. On June 13, 2017, the State of Vermont

filed a Request for a Hearing and Petition for Leave to Intervene submitting two contentions challenging the proposed license transfer, and, on June 27, 2017, the New England Coalition (collectively, with the State of Vermont, "Petitioners") also filed a Request for a Hearing and Petition for Leave to Intervene with two contentions against the proposed license transfer. On March 7, 2018, and March 12, 2018, the Petitioners filed notices of the anticipated withdrawal of their hearing requests pursuant to a settlement agreement between the Applicants and others, including the Petitioners. The Petitioners requested that their hearing requests be held in abeyance until the Vermont Public Utility Commission acted on the settlement agreement. On April 12, 2018, the Commission granted the Petitioners' motion to hold the proceeding in abeyance pending further notification by the Petitioners. Public comments were also received on this application for license transfer. They are summarized in the Safety Evaluation of this license transfer request.

The staff notes, by letter dated May 25, 2018 (ADAMS Accession No. ML18150A315), in support of the license transfer request, that NorthStar submitted a request for an exemption to 10 CFR 50.82(a)(8)(i)(A) to use up to $20 million of the VY trust (on a revolving basis) to pay for spent fuel management expenses. The staff approved the exemption request on October 11, 2018 (ADAMS Accession No. ML18274A246). The exemption is being issued simultaneously with this Order.

Pursuant to 10 CFR 50.80, no license for a production or utilization facility, or any right thereunder, shall be transferred, either voluntarily or involuntarily, directly or indirectly, through transfer of control of the license to any person, unless the Commission gives its consent in writing. Upon review of the information in the application and other information before the Commission, and relying upon the representations and agreements contained in the application,

the NRC staff has determined that NorthStar VY and NorthStar NDC are qualified to be the holders of the licenses, and that the direct and indirect transfer of the licenses, as described in the application, is otherwise consistent with applicable provisions of law, regulations, and orders issued by the Commission pursuant thereto, subject to the condition set forth below.

Upon review of the application for a conforming amendment to the VY license to reflect the direct and indirect transfer of the VY licenses, the NRC staff determined the following:

(1) The application for the proposed license amendment complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I.

(2) There is reasonable assurance that the activities authorized by the proposed license amendment can be conducted without endangering the health and safety of the public, and that such activities will be conducted in compliance with the Commission's regulations.

(3) The issuance of the proposed license amendment will not be inimical to the common defense and security or to the health and safety of the public.

(4) The issuance of the proposed license amendment is in accordance with 10 CFR Part 51 of the Commission's regulations, and all applicable requirements have been satisfied. The findings set forth above are supported by an NRC safety evaluation dated October 11, 2018, which is available at ADAMS Accession No. ML18242A639.

III.

Accordingly, pursuant to Sections 161b, 161i, 161o, and 184 of the AEA, 42 U.S.C. Sections 2201(b), 2201(i), 2201(o), and 2234; and 10 CFR 50.80, 10 CFR 72.50, and 10 CFR 50.90, IT IS HEREBY ORDERED that the application for the direct and indirect transfer of the licenses, as described herein is approved for Vermont Yankee Nuclear Power Station and the ISFSI, subject to the following conditions:

(1) Prior to the closing of the license transfer, NorthStar NDC and NorthStar VY shall provide the Directors of NRC's Office of Nuclear Material Safety and Safeguards (NMSS) and Office of Nuclear Reactor Regulation (NRR) satisfactory documentary evidence that they have obtained the appropriate amount of insurance required of a licensee under 10 CFR 140.11(a)(4) and 10 CFR 50.54(w) of the Commission's regulations, consistent with the exemptions issued to VY on April 15, 2016.

(2) NorthStar Vermont Yankee, LLC and NorthStar Nuclear Decommissioning Company, LLC shall take no action to cause NorthStar Group Services, Inc., to void, cancel, or modify the $140 million Support agreement to provide funding for Vermont Yankee as represented in the application without prior written consent of the Director of the Office of Nuclear Reactor Regulation.

(3) NorthStar Vermont Yankee, LLC shall obtain a performance bond if a Settlement Agreement with the U.S. Department of Energy (DOE), on DOE reimbursements for spent fuel management expenses, is not entered into by January 1, 2022. The performance bond will be effective January 1, 2022, initially in the amount of $4.3 million, and it will be renewed annually. This amount covers the annual amount of Independent Spent Fuel Storage Installation (ISFSI) operation and maintenance

(O&M) costs projected for 2022-2024. If a settlement is not reached by January 1, 2024, this amount will be increased to $9.3 million, which covers the annual amount of ISFSI O&M costs projected for years after 2024.

IT IS FURTHER ORDERED that, consistent with 10 CFR 2.1315(b), the license amendment that makes changes, as indicated in Enclosure 2 to the cover letter forwarding this Order, to conform the license to reflect the subject direct and indirect license transfer, is approved. The amendment shall be issued and made effective within 30 days of the date of when the proposed direct and indirect license transfer action is completed.

IT IS FURTHER ORDERED that NorthStar NDC and NorthStar VY shall, at least 2 business days prior to closing, inform the Directors of NMSS and NRR in writing of the date of closing of the license transfer for VY and the ISFSI. Should the transfer of the license not be completed within 1 year of this Order's date of issuance, this Order shall become null and void; provided, however, that upon written application and for good cause shown, such date may be extended by order.

This Order is effective upon issuance.

For further details with respect to this Order, see the initial application dated February 9, 2017, as supplemented by letters dated April 6, 2017, August 22, 2017, August 28, 2017, December 4, 2017, December 22, 2017, May 21, 2018, and June 28, 2018, and the associated NRC safety evaluation dated October 11, 2018, which are available for public inspection at the Commission's Public Document Room (PDR), located at One White Flint North, 11555 Rockville Pike (first floor), Rockville, Maryland. Publicly available documents are accessible electronically through ADAMS in the NRC Library at

http://www.nrc.gov/reading-rm/adams.html. Persons who encounter problems with ADAMS should contact the NRC's PDR reference staff by telephone at 1-800-397-4209 or 301-415-4737 or by e-mail to pdr.resource@nrc.gov.

Dated at Rockville, Maryland this 11TH day of October 2018.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Marc L. Dapas, Director
Office of Nuclear Material Safety
and Safeguards.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SECRETARY

July 2, 2019

Stephanie Garcia Richard
State of New Mexico
Commissioner of Public Lands
310 Old Santa Fe Trail
P.O. Box 1148
Santa Fe, NM 87504-1148

Dear Commissioner Richard:

On behalf of the U.S. Nuclear Regulatory Commission, I am acknowledging receipt of your letter of June 19, 2019, addressed to Krishna Singh of Holtec and copied to Chairman Svinicki regarding the license application from Holtec International for a consolidated interim storage facility (CISF) in New Mexico.

Because your letter relates to subjects raised during adjudication of the application, some of which are currently before the Commission on appeal, a copy of your letter and this acknowledgment will be served on the parties in the Holtec CISF adjudication.

Sincerely,

Denise L. McGovern

Denise L. McGovern
Acting Secretary

Stephanie Garcia Richard
COMMISSIONER

State of New Mexico
Commissioner of Public Lands

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June 19, 2019

Krishna P. Singh
President and CEO
Holtec International
Krishna P. Singh Technology Campus
1 Holtec Blvd.
Camden, NJ 08104

Dear Dr. Singh:

I write regarding Holtec International's stated plans to build and operate a nuclear waste storage facility in western Lea County, New Mexico, near the Eddy County line. In the course of applying for a 40-year permit from the United States Nuclear Regulatory Commission (NRC) to deposit in New Mexico up to 120,000 metric tons of highly radioactive waste from nuclear facilities across the United States, Holtec has stated that its proposal enjoys "overwhelming support" in the state. In fact, a number of New Mexico industry associations, from the New Mexico Cattle Growers' Association to the Permian Basin Petroleum Association, recently have expressed serious concerns about – and in some instances outright opposition to – Holtec's proposal. Along with elected officials and non-profit organizations, they have raised significant questions about the effect of the proposed nuclear waste storage site on New Mexico's oil and gas industry, farm and ranch economy, and environment. This letter will not restate those concerns, which are a matter of public record.

Instead, as New Mexico's Commissioner of Public Lands, with direct oversight of mineral leasing at the location of Holtec's planned facility, I write to express my safety concerns and to address several misrepresentations that Holtec has made to the NRC and New Mexicans about its control of the proposed disposal site as well as agreements that it claims to have secured from New Mexico State Land Office mineral lessees. The State Land Office has reviewed a number of Holtec's submissions to the NRC, including the company's Facility Environmental Report (FER) and Safety Analysis Report (SAR). Those

submissions contain statements that have the potential, intended or not, to mislead federal regulators and the public alike, and require immediate correction.

The site for Holtec's proposed nuclear waste facility (the Site) is located in Section 13, Township 20 South, Range 32 East, and portions of Section 17 and 18, Township 20 South, Range 33 East, between the cities of Hobbs and Carlsbad. Holtec has repeatedly and publicly characterized the Site as under its control. *See, e.g.*, FER 2.2.1. In fact, the subject land is a split estate; while Eddy-Lea Energy Alliance, LLC privately owns the surface estate, the State of New Mexico, through the New Mexico State Land Office, owns the mineral estate. The State Land Office's control of the Site's mineral estate is not disclosed in the FER or other NRC submissions. To the contrary, in its filings with the NRC, Holtec appears to have entirely disregarded the State Land Office's authority over the Site's mineral estate. Holtec sent notice of its initial license application in March 2017 to over 60 elected and appointed government officials, but failed to include the State Land Office. The company's subsequent filings continue to ignore the State Land Office's legal interest in the Site. For example, Table 1.4.1 of the FER lists all applicable regulatory requirements, permits and required consultations – but conspicuously omits any reference to the State Land Office.

As you know, the Site is located within the Permian Basin, one of the world's most productive oil and gas-producing regions, and there is significant oil and gas development (as well as potash mining) in the Site's immediate vicinity. Holtec claims throughout its NRC submissions that it has secured the agreements of mineral lessees on or near the Site to forebear from certain development activities. For instance, Section 2.4.2 of the FER states that "[b]y agreement with the applicable third parties, the oil drilling and phosphate extraction activities have been proscribed at and around the site and would not affect the activities at the site." Along similar lines, Section 2.6.4 of the SAR notes: "With regard to potential future drilling on the Site, Holtec has an agreement [2.6.9] with Intrepid Mining LLC (Intrepid) such that Holtec controls the mineral rights on the Site and Intrepid will not conduct any potash mining on the Site. Additionally, any future oil drilling or fracking beneath the Site would occur at greater than 5,000 feet depth, which ensures there would be no subsidence concerns [2.1.8]."

Holtec's claim that it has secured third-party agreements for control of the Site is incomplete at best. Site control generally refers to ownership of, or a leasehold interest in, a right to develop a particular tract of land. Holtec does not "control" the "mineral rights on the Site." Instead, Holtec only has an agreement with a single company, Intrepid, relating to that company's potash mining – an agreement that has yet to be approved by the State Land Office, under whose authorization Intrepid conducts its mining activities on the Site. The State Land Office's oil and gas lessees, meanwhile, confirm they have not entered into agreements with Holtec to suspend or limit their oil and gas development to accommodate Holtec's planned nuclear waste disposal facility. In addition, there are other mineral resources potentially present on the Site that may fall within the State Land Office's mineral estate that are not addressed in Holtec's filings at all.

In addition to misstating its control over the Site, Holtec also treats as a foregone conclusion the State Land Office's ability and desire to restrict oil and gas drilling on the Site. Holtec, through the Eddy-

Lea Energy Alliance, has proposed that the State Land Office impose a negative easement called a "land use restriction or condition" on all mineral development on the Site, including a ban on oil and gas development between the surface and a depth of 3,000 feet, and a prohibition on any directional or horizontal wells bottomed beneath the site that Holtec believes might "disturb or conflict" with its use of the site. The State Land Office has not approved any such restriction, which would likely trigger legal challenges from businesses that already are conducting operations on the Site pursuant to their existing mineral leases.

The State Land Office's oil and gas leases on and adjacent to the Site do not impose any depth restrictions on drilling activities. Contrary to Holtec's assurances that "any future oil drilling or fracking … would occur at greater than 5,000 feet depth," the State Land Office's analysis demonstrates the existence of numerous active oil and gas wells within a three-mile radius of the Site at depths of 5,000 feet or less.

In addition, two of the State Land Office lessees on or immediately adjacent to the Site, COG Operating, LLC and EOG Resources, Inc., raise significant concerns about the proposed project and the land use restriction that Holtec requires, particularly its implications for salt water disposal wells, pipelines, and horizontal wells underneath the Site that Holtec might determine – using unknown criteria – will "disturb or conflict" with its nuclear waste storage operations. Both companies advise that they will explore all legal options if the State Land Office were to impose a restriction on oil and gas activities that are permitted under their current leases, along the lines of what Holtec seeks. For those reasons, it is difficult to take at face value Holtec's representation in its May 23, 2019 letter to the State Land Office that "Oil and Gas is not affected by the facility."

The International Atomic Energy Agency appears to share the State Land Office's and its lessees' concerns about the unknown interaction between nuclear waste storage and preexisting oil and gas development on the very same tract of land. In a 2007 publication, it explains that "[a]ny potential site will require an adequately controlled <u>single-use land area</u> to accommodate storage facilities," and that potential waste disposal sites should "<u>avoid land with exploitable mineral and energy resources</u>." International Atomic Energy Agency, <u>Selection of Away-From-Reactor Facilities for Spent Fuel Storage: A Guidebook</u>, IAEA-TECDOC-1558 (Sept. 2007) at 3.2.2 (pp. 23-24) (emphases added). Despite Holtec's assurances to the NRC and to New Mexicans, it does not appear that your company has undertaken a thorough and critical analysis of the possible conflicts between your nuclear waste storage proposal and the vital economic activities that are already taking place on the Site.

Finally, while I appreciate Holtec's attendance at a February 19, 2019 meeting at the State Land Office to overview the company's plans, a number of serious questions that I and my staff raised at that meeting remain unanswered. Holtec to date has not responded to our inquiry about the effects that its proposed operations will have on oil and gas lessees' present or future fracking activities. In addition, we asked Holtec to identify the worst case scenario for an accident or other adverse event at the Site, and explain how the company would respond to such a contingency. To date, we have not received any

meaningful response to this inquiry, an omission that requires the State Land Office to assume that Holtec has not sufficiently analyzed the risks posed by its planned operations or is unwilling to do so.

If Holtec's proposal moves forward, nuclear waste likely would remain in southeastern New Mexico until 2048 at the earliest, and possibly much longer since there is no designated permanent repository anywhere in the nation for high-level radioactive waste. As the Commissioner of Public Lands, I am deeply concerned about the misrepresentations Holtec made to the NRC about purported agreements and restrictions regarding mineral leasing at the Site that do not exist and may very well never ever exist. Understanding the extent of oil and gas operations and other mining activities that may be conducted at the Site is essential to accurately assessing the risks of Holtec's planned nuclear storage operations. Holtec's NRC filings are materially inaccurate in this regard. Given these safety concerns, and lack of consideration for the State Land Office's fiduciary responsibilities, I do not believe that Holtec's proposed nuclear storage project is in the best interests of the State Land Office, its lessees, and its beneficiaries.

Sincerely,

Stephanie

Stephanie Garcia Richard
Commissioner of Public Lands

cc: Hon. Rick Perry
Secretary, United States Department of Energy

Hon. Kristine Svinicki
Chair, United States Nuclear Regulatory Commission

Hon. Michelle Lujan Grisham
Governor of the State of New Mexico

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of HOLTEC INTERNATIONAL (HI-STORE Consolidated Interim Storage Facility)	))))))))	 Docket No. 72-1051-ISFSI

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing **Letter from NRC Acting Secretary Denise McGovern to Commissioner Richard** have been served upon the following persons by Electronic Information Exchange (EIE).

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[Original signed by Krupskaya T. Castellon]
Office of the Secretary of the Commission

Dated at Rockville, Maryland,
this 2nd day of July, 2019

ELECTRIC POWER RESEARCH INSTITUTE

Connecticut Yankee Decommissioning Experience Report

Detailed Experiences 1996-2006

LICENSED MATERIAL

Technical Report

Connecticut Yankee Decommissioning Experience Report

Detailed Experiences 1996-2006

1013511

Final Report, November 2006

EPRI Project Manager
S. Bushart

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CITATIONS

This report was prepared by

Suncoast Solutions, Inc.
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Principal Investigator
R. McGrath

This report describes research sponsored by the Electric Power Research Institute (EPRI).

The report is a corporate document that should be cited in the literature in the following manner:

Connecticut Yankee Decommissioning Experience Report: Detailed Experiences 1996-2006.
EPRI, Palo Alto, CA: 2006. 1013511.

REPORT SUMMARY

Several U.S. nuclear power plants entered decommissioning in the 1990s. Based on current information, the next group of plants whose license will expire will not begin decommissioning for nearly a decade. This report provides detailed information on the decommissioning of one power reactor – Connecticut Yankee, in order to provide their experience for future plants.

Background
Over the past ten years, EPRI developed and published a number of lessons learned documents and workshop proceedings related to decommissioning. They provide a sound reference base for reactor facilities that will eventually undergo decommissioning. EPRI developed many of these experience reports and workshops in conjunction with U.S. nuclear plants currently in different phases of decommissioning. In order to capture additional essential experience for future decommissioning projects, EPRI carried out a pilot effort to gather select detailed information from the Maine Yankee site while it was in the later stages of decommissioning. This report details the decommissioning of Connecticut Yankee.

Objectives
- To summarize the decommissioning experience of a power reactor in the end stages of decommissioning.
- To provide lessons learned for future plants entering decommissioning.

Approach
The project team gathered survey information from managers at current decommissioning facilities to determine areas of interest to future decommissioning managers. During the time of the preparation of this report, the principal investigator was also an employee of Connecticut Yankee. With the approval of CY management, the principal investigator retrieved much of the information contained in this report from personal files. The project team gathered additional information during onsite interviews with several Connecticut Yankee managers, and through other references and sources. In particular, they focused on specific lessons learned for future plants entering decommissioning, and recommendations for current operating plants to improve performance for future decommissioning.

Results
EPRI performed a similar effort to report decommissioning experiences at the Maine Yankee Plant. As the Maine Yankee report was the pilot for this program, the Connecticut Yankee report that follows uses the same format and sequence of topics so that the reader can compare experiences between the two facilities. The decommissioning experience and lessons learned from Connecticut Yankee is presented in the areas of:

- Pre-shutdown actions and analyses
- Transition activities from operations to decommissioning
- Use of Decommissioning Sub-Contractors
- Fuel Storage Options
- Regulatory and Stakeholder interaction
- Specific Technologies used
- Site Closure Issues
- Monitoring and Remediation for Groundwater

EPRI Perspective

One of the key objectives of the EPRI Decommissioning Technology Program is to capture the good practices and lessons learned from plants currently undergoing decommissioning. Several major plant decommissioning programs are nearing successful conclusion and EPRI is documenting relevant experiences to aid future decommissioning activities, both in the U.S. and internationally.

Keywords

Decommissioning
Site closure
License termination

ACKNOWLEDGMENTS

Suncoast Solutions, Inc. wishes to thank Connecticut Yankee Atomic Power Company for its participation and cooperation in the development of this document. In particular, thanks go to the following individuals for their insights and information used in the preparation of this report.

- Brian Couture – RCRA Program Manager
- Jerry Fan – Engineering Manager
- Roy Haight – Waste Manager
- Clayton Melin – Project Schedule Manager

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7
USE OF TECHNOLOGY

Lessons Learned/Recommendations

- The segmentation of the Reactor Vessel Internals at a nuclear plant can be very challenging from a personnel exposure, cost and schedule perspective and requires careful planning and preparation.
- Transportation of large components such as the Steam Generators and Reactor Vessel can present unique challenges due to the limited disposal and transportation options.
- Many building demolition activities generate large volumes of radioactive waste very quickly. Waste packaging and transportation techniques need to included this factor to avoid space problems for the decommissioning.

This section will discuss other major decommissioning projects that have not already been discussed that involve significant technologies or were otherwise challenging.

Shipment and Disposal of Primary Components

Steam Generator Removal, Shipment and Disposal

The removal of the CY steam generators was not overly challenging as removals and in some cases replacements had been successfully accomplished at a number of other nuclear power plants. At CY the upper portion of the steam generator (called the Steam Dome) was separated from the lower portion, with a horizontal cut, and shipped to the Energy Solutions (formally Envirocare) disposal site in Clive, Utah by rail (after a about a 8 mile [13.3 km] road transport via multi axle transporter to a nearby rail spur). The lower portion of the steam generator containing the channel head and tube bundle was originally planned to be shipped primarily by barge to the Barnwell Disposal Site in South Carolina. Due to low water levels in the Savannah River from an extended drought, barge traffic was not possible at the time that the steam generators were removed. A route using barges to South Carolina and rail lines from the South Carolina coast was developed and the shipment was accomplished without incident.

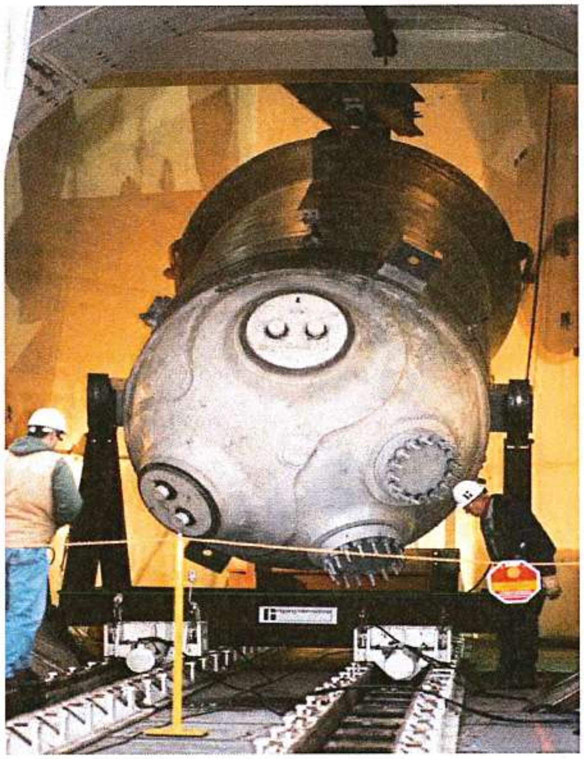

Figure 7-1
Downending of Steam Generator Lower Assembly

Figure 7-2
Moving S/G Lower Assembly to Barge Slip

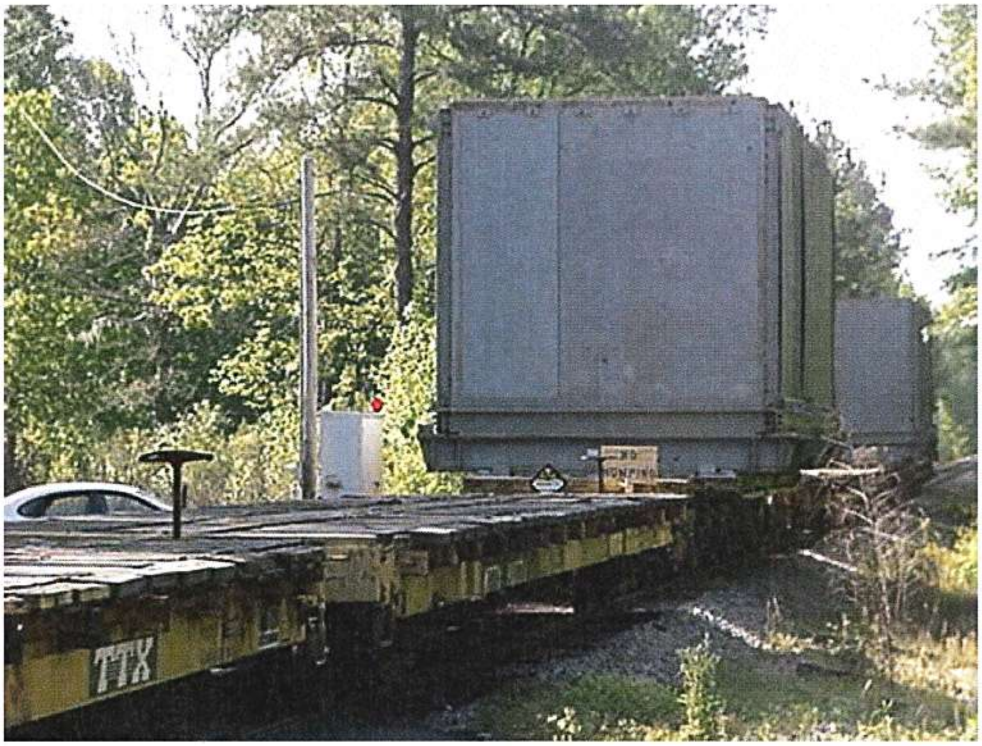

Figure 7-3
Shipment of S/G Lower Assemblies by Rail from Coast of South Carolina to Barnwell

Reactor Coolant Pump and Pressurizer

The removal and shipment of the reactor coolant pumps and the pressurizer was also fairly straightforward and accomplished without incident. Due to the relatively low activity levels of these components, shipment was by rail to the Energy Solutions facility as was performed for the steam generator domes.

Reactor Vessel Removal and Shipping

The removal and shipment of the CY reactor vessel was not that different and any more challenging than the shipment of the steam generators or reactor shipments from other facilities. The low water levels in the Savannah River continued to be a concern up until a few months before the reactor vessel was ready for shipment. Due to the larger size of the reactor vessel, shipment by rail from the South Carolina coast was not an option. The weather cooperated in the period directly before the scheduled reactor shipment and considerable rainfall created enough flow in the Savannah River to accommodate a barge the size of that required for the reactor vessel for transit to Barnwell.

The HNP discharge canal down which the reactor would be shipped had also silted up to the point that the barge could not transit it. A maintenance dredging was performed and the reactor was shipped to and disposed at Barnwell without incident.

Reactor Internal Segmentation

Segmentation Planning

The purpose of the internals segmentation project was to separate those portions of the reactor that were Greater than the Class C (GTCC) waste disposal concentrations from the remainder of the reactor. This was due to a 50,000 curie (1.85 E+15 Bq) per package limit at the Barnwell disposal facility. These requirements resulted in the removal of approximately 750,000 curies (2.8 E+16 Bq) from the Connecticut Yankee Reactor Vessel. For CY it was decided that the GTCC material would be cut so as to fit into canisters that are the size of CY fuel assemblies (FAS canisters). After being placed in this configuration, the FAS canisters would be placed into canisters and concrete storage casks that are the same size as those to be used to store fuel at the ISFSI facility. As the GTCC material could not be shipped to any currently operating site, the future DOE fuel storage repository is believed to be the final location of the GTCC waste.

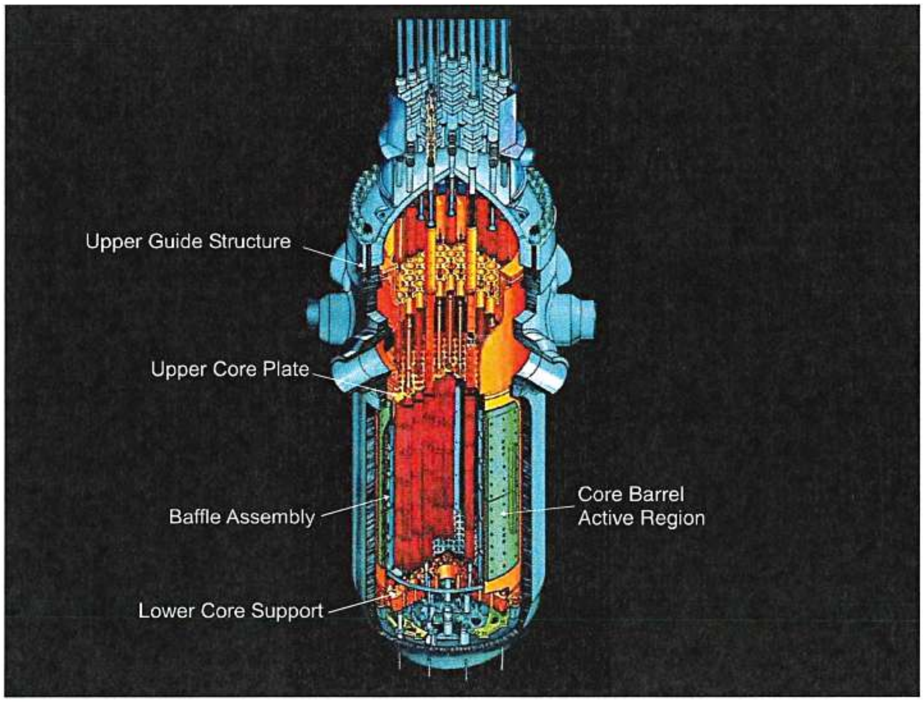

Figure 7-4
CY Reactor Vessel and Internal Components

The primary cutting technology utilized was cutting using an abrasive water jet. Probably the most significant problems involved the segmentation cutting equipment and the filtration equipment used during the segmentation project. Metal Disintegration Machining was also used for certain tasks during the segmentation project.

A key safety consideration in the segmentation process included prevention of any inadvertent removal from the cavity of any highly activated components. Contamination control and control of airborne contamination were also a key consideration during segmentation planning.

As the vendor selection was carried out as part of the turnkey contract that Connecticut Yankee had with its Decommissioning Operations Contractor (DOC), details of the selection of the internals segmentation specialty contractor are confidential.

Tooling and Testing

The majority of the segmentation was performed using an abrasive water jet. Garnet was used as the abrasive media. Metal discharge machining (MDM) was used to remove the lower core support plate bolts and to remove the bolts from the upper internals.

The majority of the cutting was done on a specially designed cutting table to segregate the cutting operations from the rest of the refueling cavity. The exception to this was the separation of the upper portion of the core support barrel. Due to the depth of the CY refueling cavity the upper six feet of the core support barrel extended approximately six feet above the water level when stored its normal support stand. This presented serious personnel exposure and airborne contamination concerns if cutting was conducted in this configuration. In order to address this problem, a specially designed stand was constructed so that core barrel (with the core shroud still in place) could be supported from the reactor vessel flange. These configurations kept the entire core barrel underwater. While in the stand, the core barrel was cut horizontally above the shroud and this segmented piece moved to the segmentation table for cutting. After the upper portion of the core barrel had been segmented, the remainder of the core barrel and core shroud was moved to the segmentation table for cutting.

A debris collections and filtration system was used to capture the cutting debris and maintain water clarity. The cutting was done on a specially designed cutting table to segregate the cutting operations from the rest of the cavity. The underwater filtration system consisted of a cyclone separator, back flushable filters, and ion exchanger vessel and a debris collection vessel.

The pre-deployment testing of the equipment used for the CY internals segmentation was a limited integrated test. As only a relatively small shallow pool was used, all of the segmentation equipment could not be tested together. As will be discussed later, experience has shown that integrated, full-scale testing is extremely important to successful internal segmentation project.

Field Experience

The segmentation of the internals of the Connecticut Yankee reactor proved to be a very challenging project. The project took approximately 29 months to accomplish with a total radiation exposure of approximately 205 person-rem (2.05 Sv). Both were well in excess of that originally estimated for the project. The problems encountered will be discussed in some detail due to the significance of the radiation exposure, schedule delays and costs incurred during this project.

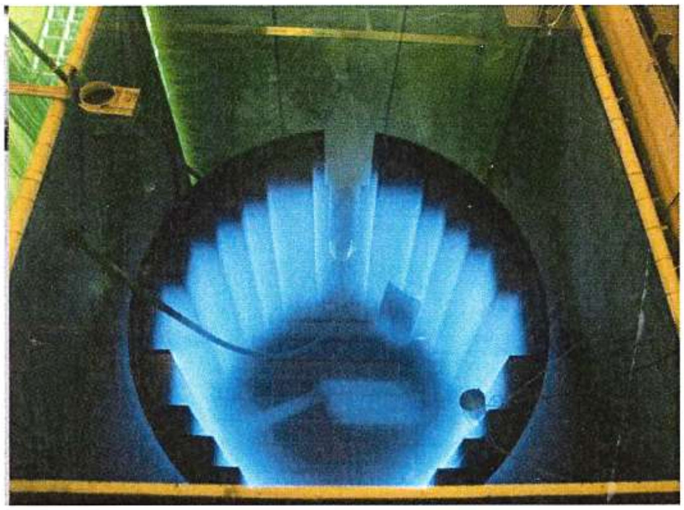

Figure 7-5
Highly Activated Core Baffle Assembly With Section Removed

Probably the most significant problems involved the abrasive water jet cutting equipment used to segment the components and the filtration equipment used during the segmentation project.

Some of the key statistics of the segmentation plan are the following:

- 1800 liner feet (549 meters) of metal cut
- 600 pieces created that were loaded into 64 FAS canisters
- FAS canisters loaded into 3 Vertical Concrete Canisters (VCCs) and moved to the ISFSI
- Approximately 650 ft^3 (18.4 m^3) of cutting debris created (Disposed of at Barnwell)
- 600 ft^3 (17 m^3) of filter and resin waste created (Disposed of at Barnwell)

The primary cutting technology (abrasive water jet) had been utilized at other facilities but the equipment used at Connecticut Yankee was not totally developed. Breakdowns and delays were the result of:

- Clogging of the abrasive feed and cutting debris transfer hoses.
- Failure of the cut to be completed full length or to the proper size requiring recutting and metal pieces with different sizes than originally planned. This resulted in difficulties in placing the pieces in the FAS cans. A stiffer cutting mast was needed.
- The size of abrasive initially used found to be less then optimal.
- Frequent replacements of the cutting nozzle.

The above factors made cutting take much longer and created a much larger volume of cutting debris (abrasive/metal chips) to be handled and disposed.

The separation tasks involving the use of MDM proceeded as planned.

The Filtration System for the segmentation project was intended to collect the cutting debris as it was generated and to maintain water clarity. Problems encountered included:

- Capture velocities and locations were not sufficient to keep pace with the quantities of debris generated.
- Piping on the filtrations skid plugged up and resulted in further reduced filtration and less effective operation.
- The filtrations skid was located underwater to keep dose to personnel down during operation but made maintenance and equipment replacement very difficult. As equipment such as pumps were not constructed for remote replacement, the skid needed to be raised to surface of the pool for repairs resulting in high personnel exposure.
- Low flow rates due to the above conditions, caused hoses to clog. This further delayed the project and extended the post cutting cleanup as hoses were simply abandoned in the pool.
- The ineffective filtration system resulted in poor cavity clarity and increased radiation exposure due to material plateout on the segmentation curtains and cavity walls.

As it became apparent that the original equipment to be used for the project was not performing adequately, additional capability needed to be added. This included additional filtration equipment both in the cavity and outside to collect cutting debris and maintain pool clarity. This equipment consisted of proven modular mobile filter and media containing vessels.

A number of exposure reduction initiatives were incorporated during the conduct of the CY Internals Segmentation Project. These included:

- Additional shielding of the bridge area
- Frequent use of high pressure wash downs
- Additional component shielding
- Establishment of a low dose waiting area

One device that was used at this point in the project was a remote manipulator arm called the "Grant Machine." This device was originally intended to cut-up and package the mirror insulation which had surrounded the beltline portion of the reactor. This manipulator proved extremely useful in cutting up and removing equipment and hoses from the cavity and vacuuming up cutting debris. The manipulator was also used to convey the hydrolazer head used to strip the paint and contamination from the cavity walls prior to cavity drain down. This equipment was highly effective and significantly saved radiation exposure, time and cost. A manipulator such as the Grant machine may have reduced the material handling problems such as dropped pieces (some which became stuck in incorrect locations) and difficulties placing pieces into FAS canisters.

Grant Machine Structural Assembly

Cavity Vacuuming With Grant Machine

Figure 7-6
Grant Machine Manipulator Arm

The internal segmentation project was completed in 2002. The final configuration of remaining internal segmentation components in the reactor vessel at the time of shipment is shown in Figure 7-7. The reactor pressure vessel was placed into a specially designed one-time use shipping package, all voids filled with grout and shipped to the Barnwell disposal site in 2003.

Cask Handling and Shipping

The liners originally intended to be used were of a special design (A-43), designed to be shipped in a TN-RAM or similar cask due to the high dose rates expected from the cutting debris. Due to the generation of much more cutting debris than planned, standard shipping liner and more available casks were used.

Duratek 8-120 casks were used for most of the waste shipping including the resin and filter media waste. Cost per shipment was lower as the cost of standard casks were lower than that of those required for higher activity waste somewhat offsetting the cost of the higher volume of waste.

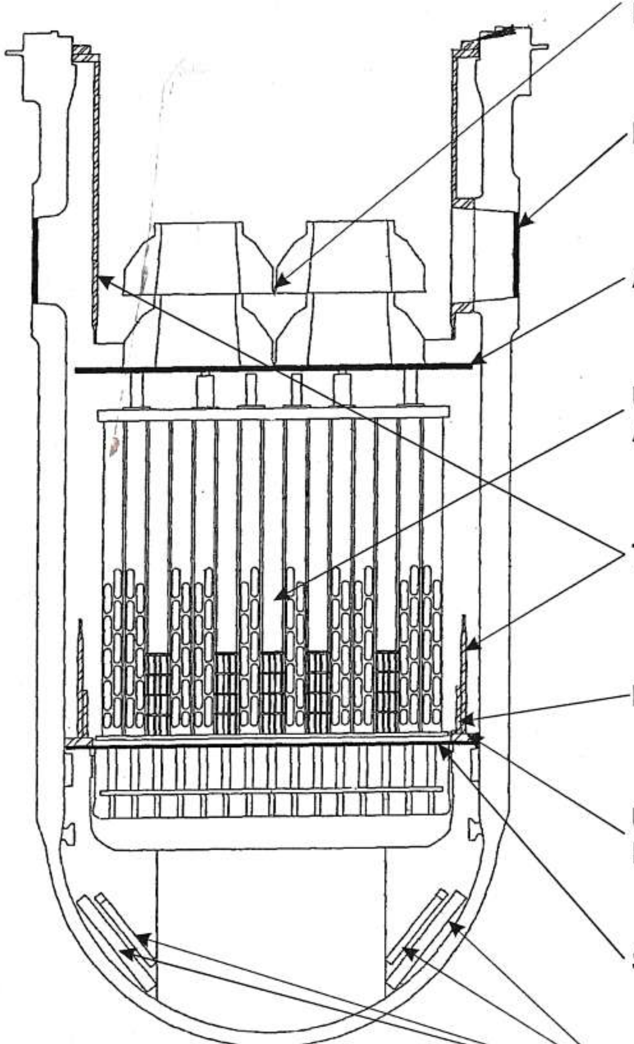

Figure 7-7
Final RPV Configuration

Cavity Cleanup

The cutting portion of the project was completed and the FAS canisters transferred to the fuel pool in the fuel building in late 2001. There remained a considerable cavity cleanup task to prepare for further decommissioning activities. The cavity contained the following:

- The original filtration system which had high dose rates due to areas clogged with cutting debris. Although originally design to be flushed to low radiation levels, this system needed to be cut up underwater and disposed of using shielded shipping casks.

- Hundreds of feet of hose that had become clogged and was discarded temporarily in the cavity.
- Large quantities of cutting debris were deposited on the bottom of the cavity when the filtration system could not collect it as it was generated.
- The segmentation table needed to be cut up underwater for packaging and disposal.

Lessons Learned

- As cutting takes time and creates secondary waste, make as few cuts as possible. CY chose to cut the GTCC material so that it could fit in relatively small canisters the size of fuel assemblies. 26 of the Fuel Assembly Sized (FAS) Canisters were then placed into a container for storage inside the Vertical Concrete Casks (VCCs) at the ISFSI. As there is no need for heat removal with GTCC, a hollow container sized to fit in the VCCs could have been used as was done at the Maine Yankee site. This approach allowed the GTCC material to be cut into much larger pieces due to the size to the container into which they would be placed. As there is less cutting with this approach, less cutting debris is generated, thereby reducing cost. This strategy will also reduce material handling problems as fewer items need to be handled.
- Evaluated equipment reliability and ease of maintenance. This evaluation should include the debris collection system and the cutting systems.
- Perform an integrated performance test of all the equipment and insure satisfactory operation prior to allowing the equipment to be mobilized to site. This full scale mockup testing will identify "bugs" in the equipment which are easier to handle before the equipment is contaminated through use in the field.
- Cutting Mast stiffness/stability is very important to accurate cutting.
- Integrate the radwaste department and demobilization planning into the project plan.
- Maintain cavity cleanliness during the cutting operations.

A number of utility decommission personnel visited the Connecticut Yankee site and lessons learned from the Connecticut Yankee segmentation were very beneficial to subsequent segmentation projects.

Containment Demolition

Due to the containment building design at nuclear plants, demolition of the structure has historically taken a great deal of time and expense. The containment building at CY consisted of a highly reinforced concrete exterior with an inside liner made of carbon steel. The interior liner is painted with polychlorinated benzene (PCB) and lead paint which complicated the demolition due to its EPA classification as a hazardous substance. The dimensions of the CY Containment Building were as follows:

- 170 feet (51.8 m) tall
- 140 feet (42.7 m) in diameter
- 4 ½ feet (1.4 m) thick cylindrical sides
- 2 ½ feet (0.8 m) thick dome roof

CY considered previous experience with demolition of large concrete containments using techniques such as the following:

- Standard techniques such as the use wrecking balls.
- Bringing the structure down using explosives.

The first technique was felt to be very time consuming as it is inefficient for structures containing a large quantity of reinforcing rebar.

The use of explosives involved the following:

- Creating large openings in the structure in the form of archways using a hydraulic hammer mounted on excavators (Hoe-rams) and cutting away the liner.
- Explosive charges are attached to the "legs" left through the creation of the archways. Using a controlled explosion, the legs are disintegrated and the upper part of the structure (essentially the hemispherical shaped dome) travels downward.
- After the dome is dropped, hoe-rams have been used to rubbalize the remainder of the structure.

As can be seen from the above, the use of explosives requires a great deal of hoe ramming to first prepare the archways and then to rubbalize the dome. Another aspect of the use of explosives is the high price of controlled explosive demolition. Considering the above, CYs subcontractor developed a new option.

The demolition of the CY containment was to be carried out exclusively using excavators fitted with hoe rams and shears. The sequence, which had never been used before, was as follows:

- Starting at grade level, approximately 15 feet (4.6 m) of interior liner was hammered loose and peeled away from the structure.
- Next, the initial procedure was to remove the majority of the 10 feet (3 m) cylinder of concrete starting at grade (section to be dropped called a lift). The concrete was rubbalize using a hoe ram and the exposed rebar sheared. Three approximately 6 feet (1.8 m) wide sections of the lift ("legs") were left during the preparation activity.
- Using an armored excavator fitted with a hoe ram, two of the remaining legs were removed from outside the structure on April 19, 2006. Once sufficient material had been removed from the leg, the structure fell the distance of 10 feet. Although no missiles were created by the drop, an additional height of concrete was crushed by the fall. Based on the observations during the first drop, subsequent drops were reduced to 5 feet (1.5 m) to lessen the force of the drop until the containment height was reduced significantly.
- After the drops the crushed material was removed from the area and the process repeated.
- As mentioned above the procedure was modified after the first drop. The length of cylindrical concrete removed per lift was reduced to approximately 5 feet (1.5 m). As the small legs used in the first drop were all crushed when one was hammered away, a much wider leg was left during subsequent drops. This allowed the structure to settle in a more controlled fashion.

- The process was repeated using 5 feet (1.5 m) lifts (increased to 10 feet (3m) drops later in the project once the mass of remaining containment was reduced) until all of the cylindrical section of the containment structure has been removed.
- Once the dome section of the structure was lowered to grade level, the dome was demolished in place as all of the structure could be reached by an excavator mounted hoe ram.

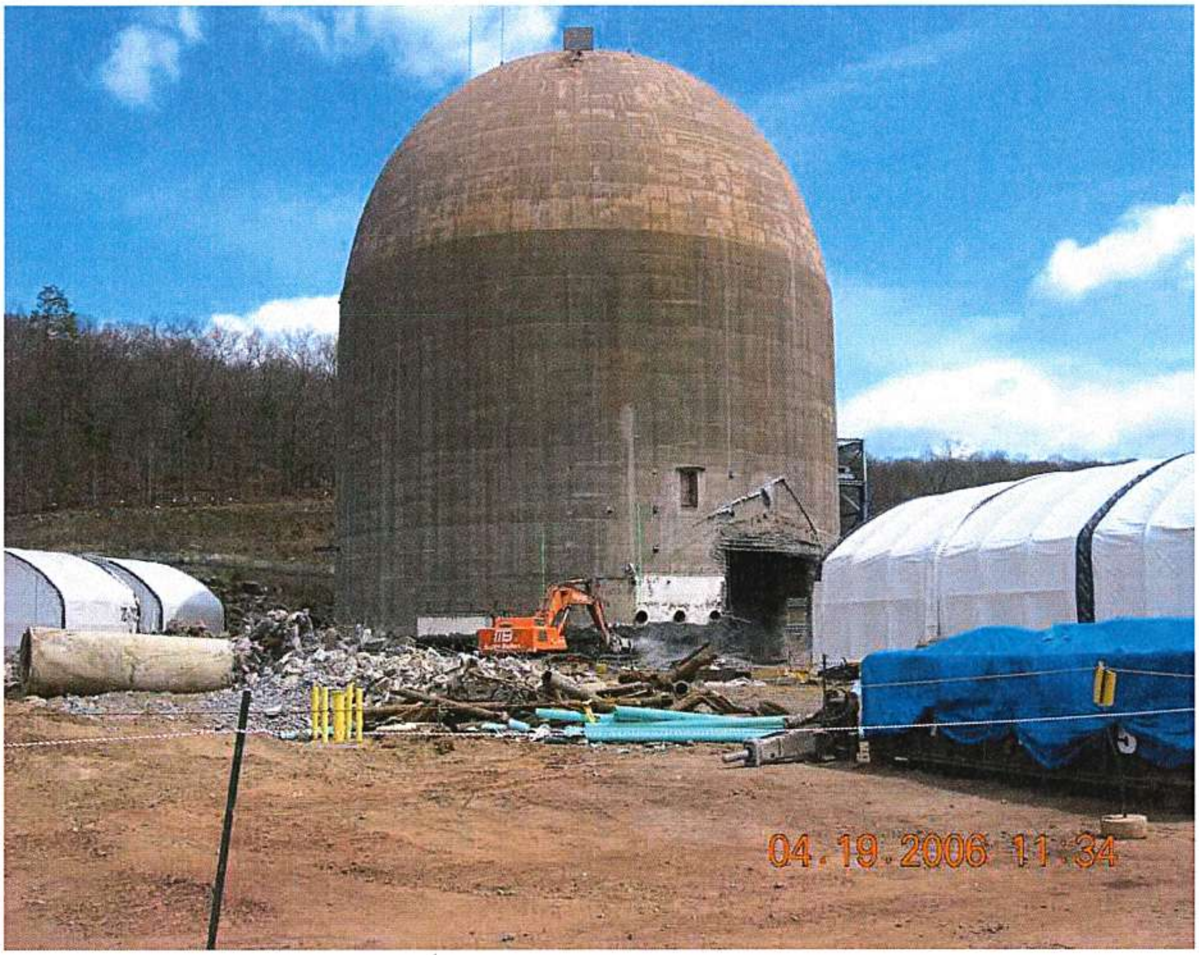

Figure 7-8
Hydraulic Hammer Removing "Leg" Prior to First Drop

Figure 7-9
Removing Concrete from Inside of "Leg" Prior to First Drop

The safety aspects of this method were strongly evaluated. For all of the work, a 75 feet (23 m) exclusion area was maintained during all hoe ramming activities. For the first 10 feet (3 m) drop, a 200 feet (61 m) exclusion area was maintained around the containment structure while the "legs" were being rubbalized. This was considered to be the distance over which any projectiles launched by the settling of the structure would lose their energy. After the experience of the first drop and with the reduced lift height, the exclusion area was reduced somewhat but never less then 75 feet (23 nm) in any direction during hammering and drops.

The demolition of the CY containment took approximately 3 months to complete, working 2 - 10 ten hour work shifts (4 days per week). This time span was shorter then originally planned and kept the containment building off the decommissioning project critical path. Project costs were reduced due to the avoidance of the cost of controlled explosive demolition.

Waste Management

A decommissioning project such as that conducted at the Connecticut Yankee Site is primarily a waste disposal project. When finished, CY will have disposed of approximately 350 million pounds (159 million Kg) of clean (i.e. no detectable radioactivity or hazardous contamination) construction waste and waste containing radioactivity and/or hazardous contamination.

The packing, transport and disposal of this quantity of material is a major undertaking resulting in a very large percentage of the overall decommissioning costs. Although involving standard techniques, the disposal of waste can be conducted so as to reduce overall project costs. Some of the more important methods are as follows:

- The size of packages used for waste shipment can affect the efficiency of the decommissioning. Building demolition debris can be created much more rapidly than it can be packaged and shipped. It is more efficient to demolish a structure, move the debris in large haulers to a staging area and package the material in the largest packages practical. For CY as the initial transport was by truck (shipments limited to approximately 40,000 lbs [18,200 Kg] of waste), intermodal packages (See Figure 7-10) proved to be sufficiently robust and were easy to load due to their open tops and 40,000 lb (18,200 Kg) capacity. Intermodal packages were required for all the waste except for the very low level waste shipped via transloading as discussed below.

Figure 7-10
Intermodal Packages for Shipment

- Shipment by rail is the least costly for long distances (i.e. distance from CY to the Energy Solutions disposal site in Clive, Utah is 2,500 miles [4,170 km]). CY did not have rail access on site, so waste bound for Energy Solutions was initially shipped by truck in intermodals to the Alaron facility in Pennsylvania, repackaged into gondola cars and shipped by rail Energy Solutions.
- As it was determined that waste from building demolitions was being created much faster than it could be packaged and shipped using intermodals and repackaging at Alaron, an alternate transloading approach was utilized. In this approach, called Transloading, concrete

demolition waste was loaded into covered dump trucks or trailer dumps and taken to a transloading facility in Worcester, Massachusetts. At that facility, the waste was dumped into gondola cars and shipped by rail to Utah. The material shipped was primarily the containment concrete from outside the liner and contained only trace levels of radioactivity. As the facility in Worcester was not licensed by the NRC, surveys were conducted at least weekly to confirm no detectable radioactivity was deposited at the facility. No radioactivity was ever detected at the Worcester or New Haven facility discussed below or in the trucks used to transport this waste.

- To further increase shipping rates, the containment rebar separated from the concrete was transloaded using a similar operation through a New Haven, Connecticut rail yard. A large magnet was used to load rebar into the gondola cars in Hew Haven.
- Due to the high quantities of building debris, the radionuclide concentrations of much of the waste is very low and qualifies for disposal at facilities such as the controlled landfills near Memphis and Oak Ridge, Tennessee. This disposal option help to reduce waste shipping through shorter transportation distances and lower disposal costs due to competition for the large volumes of waste generated.
- The physical form of the waste can drastically affect the costs of disposal. An example of this is the disposal of concrete building debris. Conventional demolition results in fairly large sized concrete chunks. Certain disposal facilities have lower costs for disposal of material that can be used as backfill for other waste. Concrete debris can be size reduced and made rebar free so as to qualify for this lower disposal costs. This technique was used at CY and the savings more then justified the cost of on-site waste sizing.

A
RADIOACTIVE WASTE VOLUMES

Table A-1 provides projections of waste quantities for decommissioning. The total weight of HNP low-level radioactive waste for disposal has been estimated at approximately 262.4 million pounds. The total estimate for "Clean" waste disposed is 116 million pounds.

Decommissioning planning at CYAPCO incorporated cost-effective waste volume reduction methods where appropriate. Significantly contaminated or activated materials were sent directly to a disposal facility.

Table A-1
Projected Waste Quantities

Radwaste Category	Weight (lbs)
Asphalt	701,036
Primary Components and High Activity LLW	2,899,299
Building Demolition Debris	221,650,366
Canal Dredging Spoils	5,927,454
Mixed Waste	132,075
Soil	34,100,434
Total Radwaste Weight	**265,410,664**

Maine Yankee Decommissioning Experience Report

Detailed Experiences 1997 - 2004

CITATIONS

This report was prepared for EPRI and Maine Yankee by

New Horizon Scientific, LLC
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Naperville, IL 60540

Principal Investigator
R. Aker

REPORT SUMMARY

Several U.S. nuclear power plants entered decommissioning in the 1990's. Based on current information, the next group of plants whose license will expire will not begin decommissioning for nearly a decade. This report provides detailed information on the decommissioning of one power reactor – Maine Yankee, in order to provide their experience for future plants.

Objective

To summarize the decommissioning experience of a power reactor in the end stages of decommissioning and to provide lessons learned for future plants entering decommissioning.

Approach

The project team gathered survey information from managers at current decommissioning facilities to determine areas of interest to future decommissioning managers. Information on these areas of interest was obtained from Maine Yankee. The information gathering included onsite interviews with several Maine Yankee managers, as well as review of information provided by Maine Yankee, and information obtained through other sources. In particular, information was gathered on specific lessons learned for future plants entering decommissioning and recommendations for current operating plants to improve performance for future decommissioning.

Results Summary

The decommissioning experience and lessons learned of Maine Yankee is presented in the areas of:

- Pre-shutdown actions and analyses
- Transition activities from operations to decommissioning
- Use of Decommissioning Operations Contractors
- Fuel Storage Options
- Regulatory and Stakeholder interaction
- Specific Technologies used
- Site closure issues

In addition, the report provides recommendations from Maine Yankee staff on actions that currently operating plants can take now to assist in eventual decommissioning activities. These

include enhancing stakeholder relations, improving contamination control both inside and outside restricted areas including strong document control, building a strong historical site assessment and enhanced ground water monitoring,

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- Eric Howes – Public & Governmental Affairs Director
- Bill Henries – Decommissioning Director
- Tom Williamson – Nuclear Safety & Regulatory Affairs Director
- Mike Whitney – Regulatory Affairs Director
- Jim Connell – Radiation Protection Manager
- George Pillsbury – Final Status Survey Principal Engineer

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1
INTRODUCTION

Over the past eight years, EPRI has developed and published a number of lessons learned documents and workshop proceedings related to decommissioning.

These lessons learned documents and workshop proceedings have provided a sound reference base for reactor facilities that will eventually undergo decommissioning. Many of these experience reports and workshops were developed in conjunction with U.S. nuclear plants currently in different phases of decommissioning.

As of 2004, many of these reactor facilities have completed a large portion of the required decontamination and remediation and anticipate the full conclusion of the decommissioning projects in the near term. Based on currently announced or submitted license extension applications, only five additional U.S. reactors will enter decommissioning prior to 2020, with the next planned shutdown not occurring until 2011.

In order to capture additional essential experience for future decommissioning projects, EPRI began a pilot effort to gather selected detailed information from a current site in the latter stages of decommissioning. An initial listing of "essential information" to be gathered was developed. This initial listing is provided in Appendix A. In order to validate this list, individuals from two facilities currently undergoing decommissioning were asked to rank the information topics on their relative benefit to future decommissioning projects.

It is interesting to note in the development of the initial listing of "essential information" the expected outcome would focus on detailed project plans, schedules, engineering analysis or similar "nuts and bolts" activities in decommissioning. These types of tasks were certainly necessary for effective and efficient decommissioning. However, there is a second level of information that is deemed significant to the efficient conduct of the decommissioning project. The information areas in this group were so-called "soft areas" including stakeholder interaction, regulatory interaction, and project decision methods (e.g., use of decommissioning operations contractor or not, wet or dry spent fuel storage, or decommissioning approach). Therefore, the information being capture was directed to both hard project data and those "soft" tasks which influence the effective conduct of the overall decommissioning project.

Maine Yankee Atomic Power Company (MYAPC) agreed to be the host site for this pilot detailed experience report. In order to gather the detailed information identified, site interviews were conducted at the Maine Yankee site and corporate offices in October 2004. Supplemental telephone interviews were conducted in November 2004. Interviewees included the President & Chief Executive Officer, Vice President & Chief Nuclear Officer, Chief Financial Officer, Regulatory Affairs Manager, Public Affairs Manager, Site Decommissioning Manager, Engineering Manager, Radiation Protection Manager and selected staff members. In addition to

the interviews, certain documentation was provided by MYAPC personnel in addition to information gathered from other sources. A summary of information sources used is provided in Section 10.

In addition to addressing questions regarding specific decommissioning experience, the MYAPC personnel were asked questions regarding how their decommissioning experience might be useful for currently operating nuclear reactors as well as for those contemplated to be built in the future. Their insights on these questions are also provided in this report.

The remainder of this document provides a brief summary of the MYAPC decommissioning project followed by summaries of the interview results and documentation reviews for each of the following topics:

- Pre-Shutdown Issues
- Transition Activities
- Use of a Decommissioning Operations Contractor (DOC)
- Fuel Storage Options
- Regulator and Stakeholder Interaction
- Engineering and Use of Technology
- Site Closure Issues

Each of the following sections begins with a brief listing of decommissioning lessons learned from Maine Yankee. In addition, a specific listing of recommendations for operating plants which would improve performance in future decommissioning is provided in Appendix F. Other items included in this report include:

- A summary project schedule is provided in Attachment B;
- A project timeline is provided in Attachment C;
- A summary of radiation exposures per major task is provided in Attachment D;
- A summary of radioactive and non-radioactive waste shipped is provided in Attachment E; and,

Maine Yankee Overview

Maine Yankee was owned by a consortium of 10 New England electric utilities representing consumers in Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. Maine Yankee, a single unit facility was located on a 820 acre site in Wiscasset, Maine and housed a three-loop pressurized water reactor rated at 2,700 MWt and 860 MWe. The reactor was designed by Combustion Engineering and the plant was built by Stone & Webster.

The following five figures provide the location of the plant as well as a site layout.

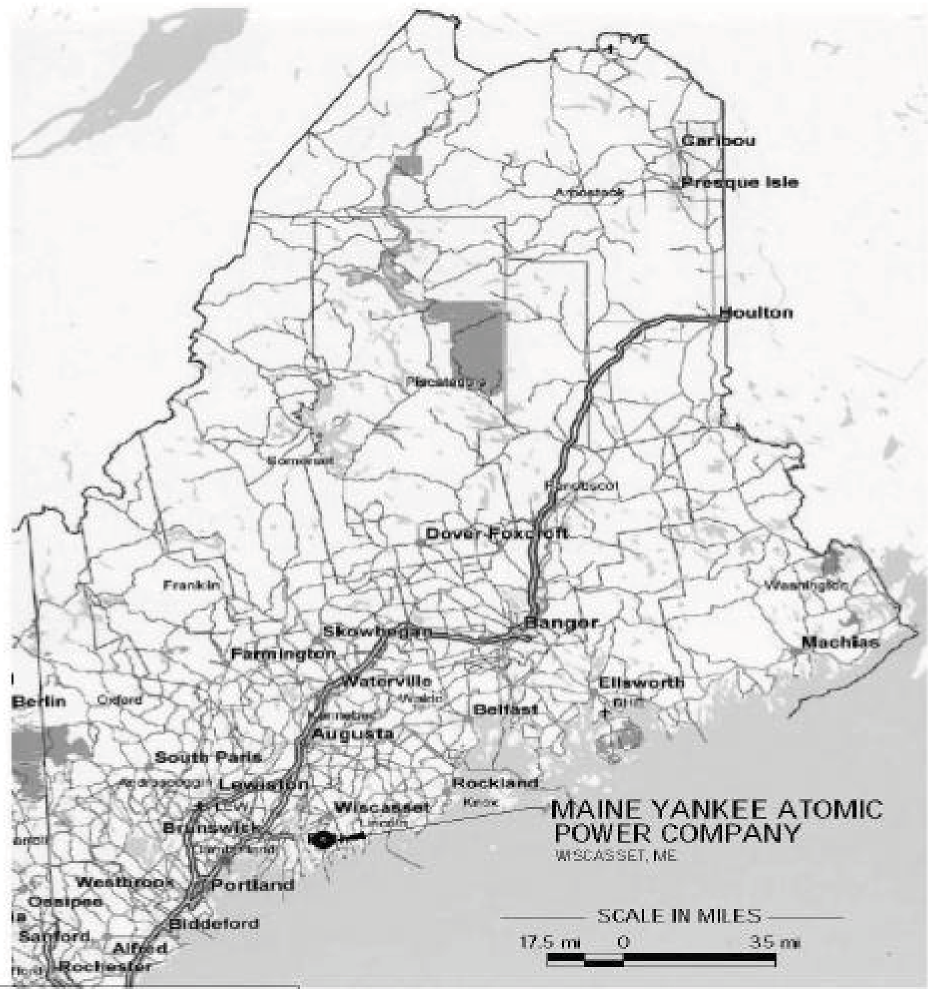


Figure 1-1 Maine Yankee Location Within Maine

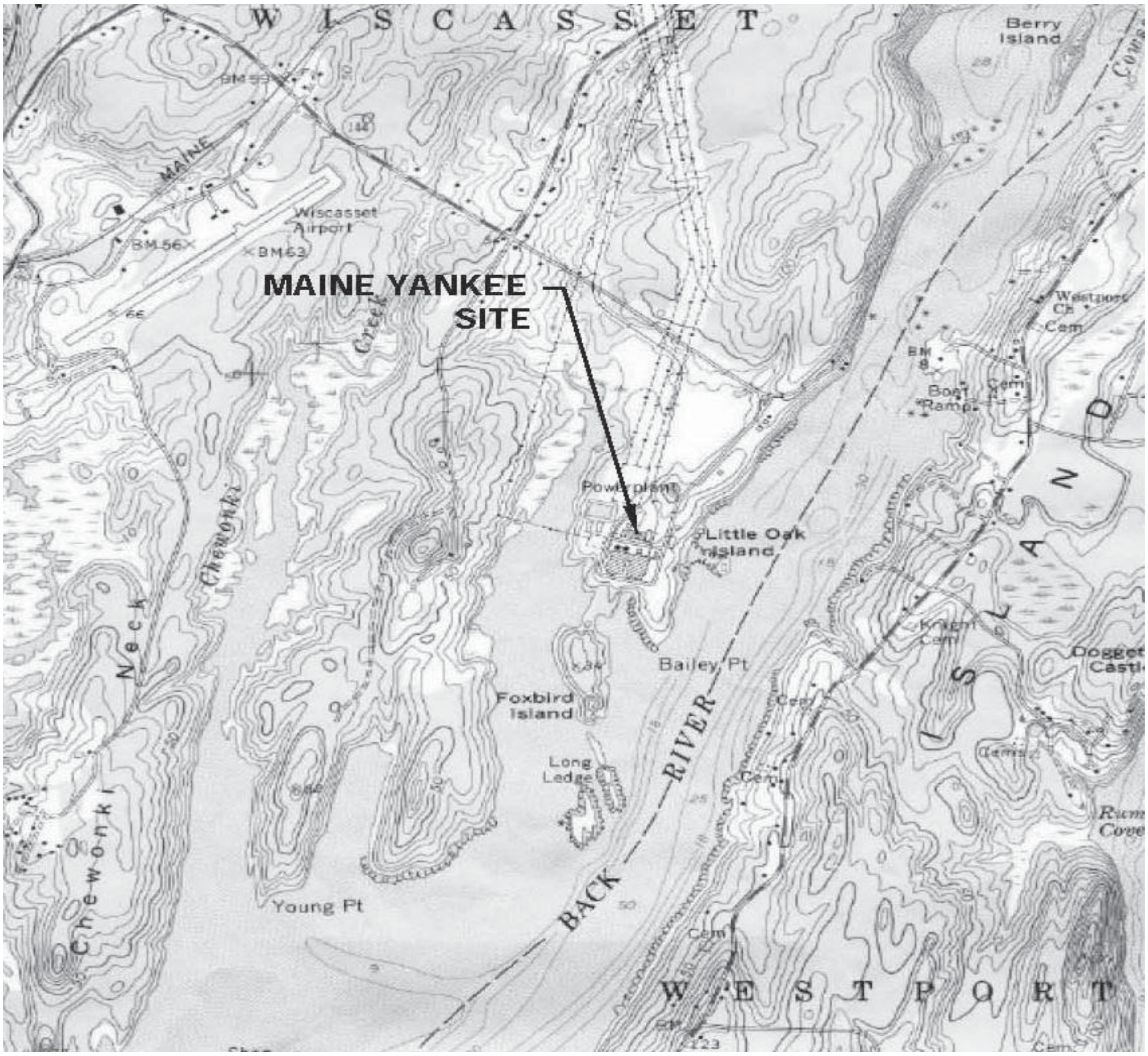


Figure 1-2 Maine Yankee Local Location

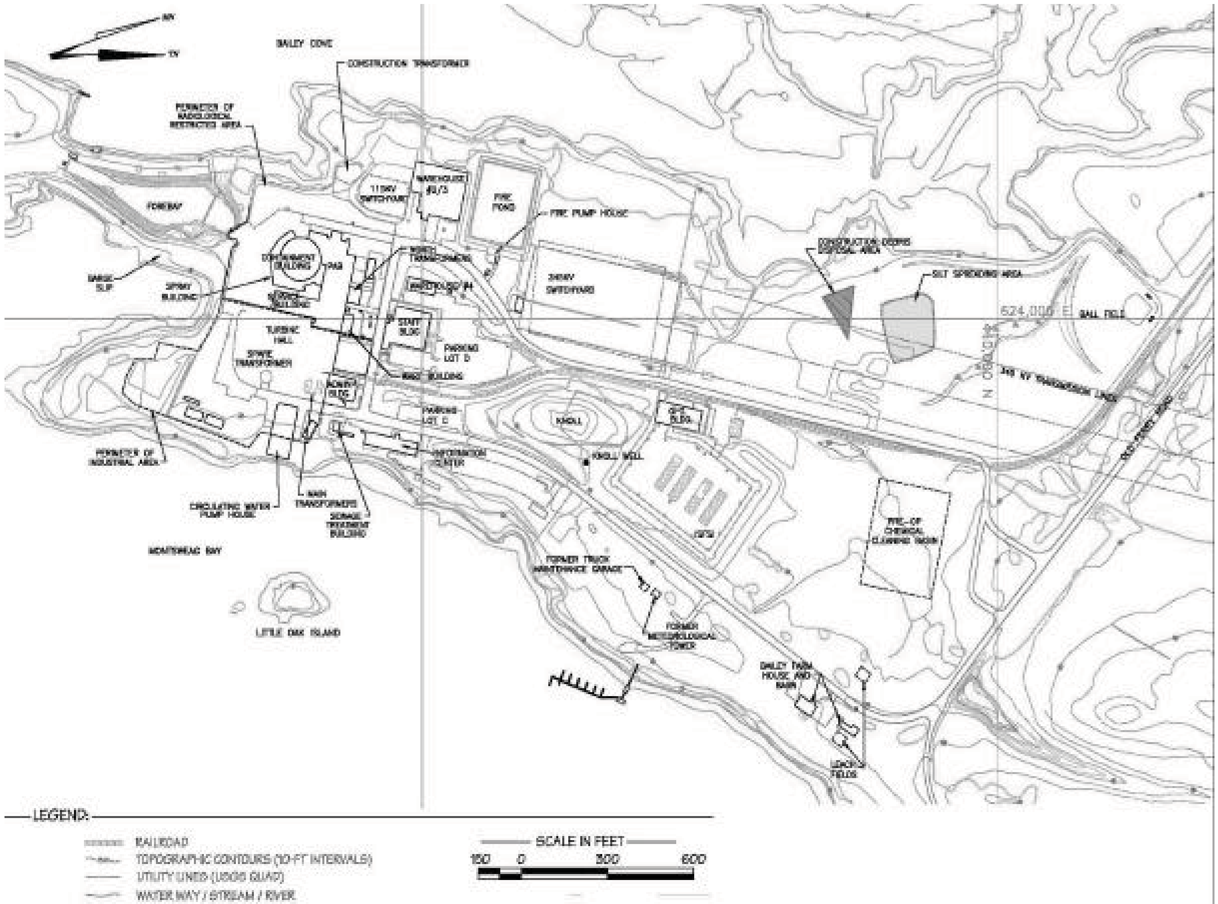


Figure 1-3 Maine Yankee Site Area Layout

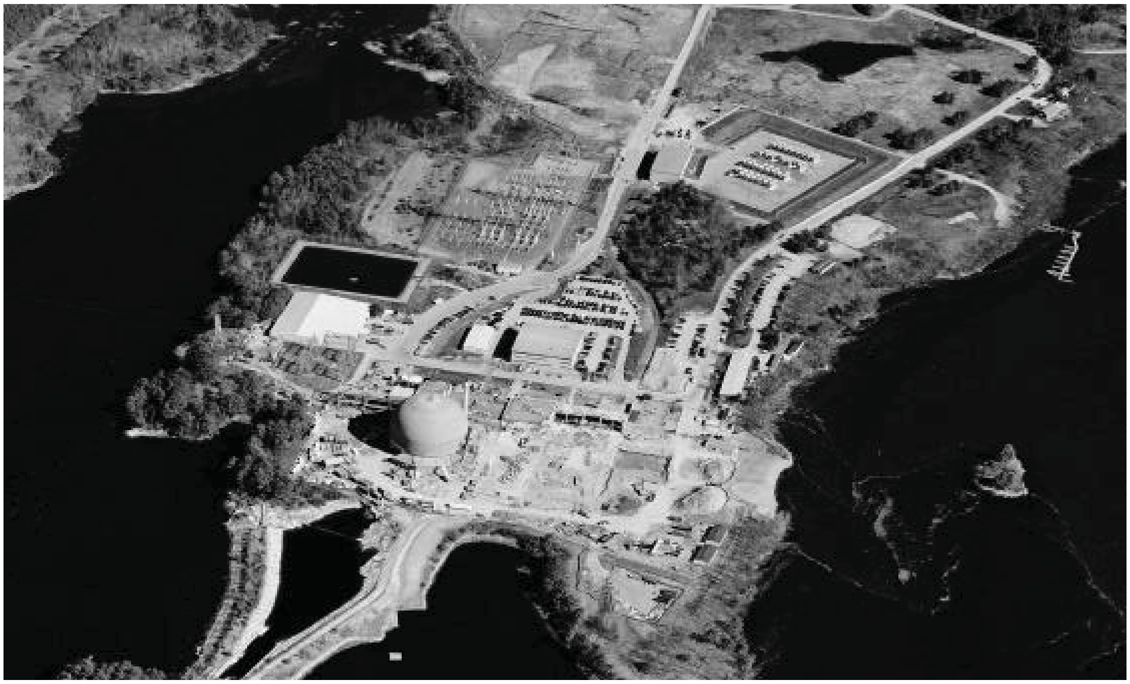


Figure 1-4 Maine Yankee Aerial View

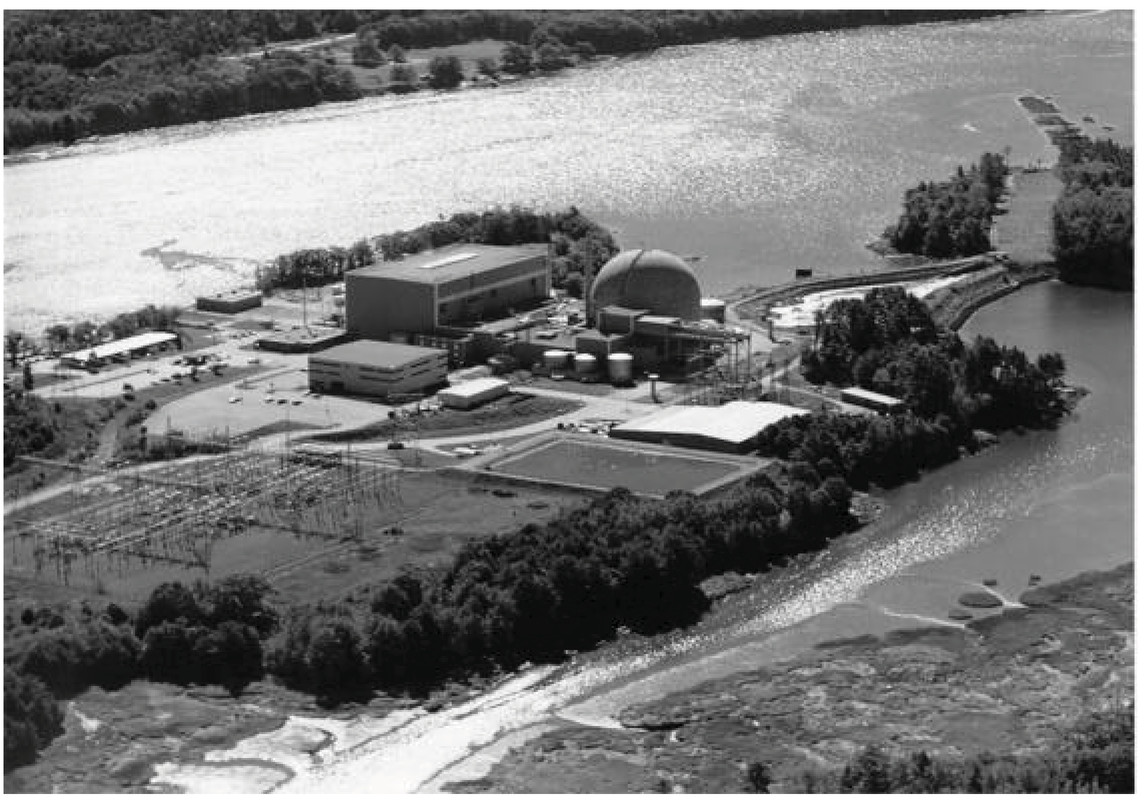


Figure 1-5 Maine Yankee Aerial View - 2

2
PRE-SHUTDOWN ISSUES

Lessons Learned/Recommendations

- If permanent shutdown is a planned evolution, pre-shutdown activities should begin in earnest approximately a year before shutdown with a dedicated team of site and corporate individuals with expertise in licensing, stakeholder interaction, engineering, project management, financial analysis, accounting and budgeting, health physics/radiation protection and human resources.

Shutdown Decision

The construction permit for Maine Yankee was issued on October 21, 1968. The Operating License was issued on September 15, 1972 allowing power operation up to 75% rated thermal power. The plant began commercial operation on December 28, 1972. In June 1973, the facility received a full power license for up to 2440 megawatts thermal (MWt), corresponding to approximately 774 megawatts electrical (MWe).

Operating license amendments were later issued allowing power operation up to 2,700 MWt. This power level corresponds to a gross electrical output of approximately 931 MWe.

In the mid 1990's, Maine Yankee encountered various operational and regulatory difficulties. In 1995 the plant was shut down for almost the entire year to repair steam generator tubes. Maine Yankee shut down for the final time on December 6, 1996 for various problems, including improper cable separation, replacement of a number of leaking fuel rods and the need to inspect the plant's steam generators. This outage was expected to last through at least August of 1997.

Based on this history, the Board of Directors conducted ongoing economic assessments of the future viability of Maine Yankee.

In May 1997, the Board of Directors announced that Maine Yankee was considering permanent closure based on economic concerns and uncertainty about operation of the plant. The Board also explored the possibility of a sale of the plant.

The results of the final economic assessment were provided to the full Board of Directors on July 30, 1997. This report noted that while there are many variables and uncertainties in the analysis, the primary ones that were found to affect the economics of the plant were:

- the projected market price of replacement power;

- the useful life of the plant;
- the unit's average capacity factor;
- the unit's variable operational costs, the costs that could be avoided if a decision is made to close the plant, and the timing and amount of decommissioning expenses; and,
- the projected restart date.

The economic assessment looked at several scenarios with three primary options being evaluated. The first option was immediate entry into decommissioning which would result in the fastest reduction in operational costs. The second option was to provide funds to preserve the plant for some months allowing for the options of plant sale or restart. The last option was to restart the unit which at that time had made substantial progress towards a target of November 1997.

The summary of the economic analysis concluded:

- The reference case assumptions (which assumed that the plant would operate until the end of its license) would result in a slight net present value (NPV) benefit to Maine Yankee's customers.
- The reference case provided the starting point for the analysis. It was not viewed as the most likely outcome.
- It was noted that each member company might conduct slightly differing economic studies, however it was believed that all the member companies would likely make the following judgments as to scenarios assumed to be more likely than the reference case, including:
  - operation of the unit for less than the remaining licensed life;
  - capacity factors below the assumed non-outage value of 95%;
  - additional capacity factor reductions to to reflect performance risks such as the extension of refueling outages or unplanned forced outages;
  - modification of the discount rate for continued operation cash flows;
  - restart later than November 1, 1997; and
  - replacement power costs 10% lower than assumed in the reference case.
- Most combinations of adjustments such as those indicated above result in substantial penalties for customers from the continued operation of Maine Yankee.

Pre-Shutdown Planning

In 1996 and 1997, initial planning efforts for decommissioning began. These efforts included:

- Drafting the Post Shutdown Decommissioning Activities Report (PSDAR);
- Beginning development of a range of exemption requests to be submitted to the NRC. These exemption requests included reductions in emergency plan requirements, reduction in

insurance requirements, and changes in technical specifications. The certifications to the NRC on permanent cessation of operations and permanent defueled status were also prepared;

- Review of a previous decommissioning cost estimate;
- Assessment of decommissioning options (prompt or deferred);
- Initial assessment of decommissioning approach – self perform or contract out (addressed in Section 4); and,
- Initial assessment of stakeholder interactions required (addressed in Section 6).

The decommissioning approach selected (prompt dismantlement) followed the economic analysis of the Board of Directors which noted that if decommissioning was the selected outcome for the site, the prompt approach was the most economically advantageous to the ratepayers.

On August 6, 1997, due to economic reasons, the Maine Yankee Atomic Power Company Board of Directors voted to permanently cease power operations and immediately initiate the decommissioning process.

3 TRANSITION ACTIVITIES

Lessons Learned/Recommendations

- Management – Select a small management group for the project with all disciplines involved for the initial decommissioning planning. It was essential to work together as a team in a generally flat organization.
- Management – Important to keep all departments involved, even when it was not obvious that the issue to address was in their area. This is because in decommissioning it is not always obvious how a seemingly unrelated task/decision could affect other departments, and also because unique and better solutions/approaches to problems were offered by those not directly related to the issue.
- Management – Over time, a generally small management team gathers sufficient knowledge about areas outside their direct management area that their insights often have the effect of adding another level of quality assurance to work activities.
- Management – In selecting personnel to remain with the decommissioning project, it is important to retain expertise and experience in construction in addition to keeping managers with operational experience. In order to support the next recommendation, it is also important to obtain personnel with expertise in construction and/or demolition experience.
- Management – A key early transition activity is moving the site mentality toward decommissioning rather than operations.
- Cold and Dark (defined in detail in the following) – Condensation made the Primary Auxiliary Building floors slippery – need to install walkway mats.
- Cold and Dark – Take specific care in the implementation of an "orange plan" (defined in detail in the following text). Lack of attention to detail can result in lines, conduit or supporting media being inadvertently cut.
- Cold and Dark – Assure low spots in lines are adequately drained. Once heat is reduced or eliminated in a facility, inadequate draining can result in fractured lines or valves due to entrained water freezing.
- Cold and Dark – Perform independent review of projects to avoid missing sneak electrical circuits from non-cold and dark buildings.

Overview

The transition period in decommissioning is generally considered the period between permanent cessation of operations and the commencement of decommissioning activities. In the case of Maine Yankee, this was the period between August 1997 and approximately July 1998 when the Decommissioning Operations Contractor (DOC) was selected. Key actions in this period consisted of:

- Submittal of various regulatory and licensing documents in order to reduce the burden of activities no longer required;
- Completion of business cases to determine decommissioning options;
- Development and submittal of Requests for Proposals (RFPs) for major decommissioning contracts;
- Planning and conduct of pre-decommissioning actions;
- Execution of critical path activities such as site assessment, reactor coolant loop chemical decontamination, and asbestos abatement;
- Selection of site personnel to remain with the decommissioning project and commencement of destaffing actions for personnel termination; and,
- Initiation of stakeholder interaction relative to decommissioning.

Transition Licensing Actions

The first licensing actions taken after the decision was announced were the submittals to the NRC certifying that Maine Yankee has permanently ceased operations and had permanently removed all fuel from the reactor vessel. These certifications were submitted to the NRC the day after the Board of Directors announced the decision to decommission.

Following these submittals, the next key step is the submittal of the Post Shutdown Decommissioning Activities Report (PSDAR). The site had PSDARs submitted by other facilities as a reference model, however needed to tailor the document to Maine Yankee site specific data such as the preliminary decommissioning schedule, cost estimate and estimates of waste volumes and radiation exposure for the project. The Maine Yankee specific PSDAR was submitted to the NRC on August 27, 1997. The PSDAR as submitted identified that license termination and site remediation should be completed approximately seven years following cessation of operations. It is noted that with the cessation of operations occurring in August of 1997, the PSDAR would suggest that the Maine Yankee decommissioning would be complete by August 2004. The current completion is scheduled for March 2005 (a schedule increase of only 8%).

After receipt of the PSDAR, the NRC conducts a public meeting in the vicinity of the reactor, normally within 90 days of the document receipt. This meeting provides the public with a summary of the decommissioning approach and timeline as provided by the licensee, and affords the NRC the opportunity to discuss the regulatory and oversight process for a decommissioning reactor. The meeting also provides an opportunity for public comment. The public meeting for Maine Yankee was held on November 6, 1997.

Licensing activities are a significant activity throughout the decommissioning project. More detail on the regulatory interactions required for Maine Yankee is provided in Section 6.

Transition Business Cases

If not already completed, several business cases or economic analyses are conducted in the transition period. These are very significant as the results form the overall approach and are the key decision inputs for the entire decommissioning project going forward.

The earliest business case is for the selection of the decommissioning approach. As noted above, the Board of Directors economic analysis had been completed for this task, resulting in the decision to proceed with prompt decommissioning.

The next significant business case is to determine the overall decommissioning project management method. The options primarily were Maine Yankee managing the project and hiring specific contractors or subcontractors as needed for project completion, hiring a general contractor who obtained all necessary subcontractors or hiring a Decommissioning Operations Contractor (DOC). The DOC approach is similar to hiring a general contractor. A general contractor provides all the labor and skills specified in the contract for a pre-set rate per labor hour (so-called "time and materials" contract). The DOC differs from the general contractor approach in that the DOC accepts some portion of the risk on a fixed price basis for the project from the licensee, in addition to providing all necessary labor and skills for the job. As discussed in Section 4, Maine Yankee selected the DOC approach.

Another business case which is typically initiated in the transition period is the approach to be taken for storage of spent nuclear fuel. At the time of Maine Yankee's shutdown, the U.S. Department of Energy (DOE) still was not in default on its contract to begin accepting spent nuclear fuel beginning January 1, 1998, but it was apparent that Maine Yankee's spent fuel would need to be maintained on site for an extended period. DOE indicated that the Yucca Mountain repository would likely not be in operations until 2010. Assuming the facility opened on the new schedule, each power reactor in the United States is allocated space in a queue for shipment of their fuel to the final repository.

One key variable in the business case for on-site spent fuel management is the selection of a date by which all the spent fuel on site is expected to have been transferred to the DOE for permanent disposition. This economic analysis is further addressed in Section 5.

Transition Requests for Proposals (RFPs) and Projects Performed

Once the decision is made for the contracting approach, detailed RFPs are developed and offered for bid. For the DOC, this is further addressed in Section 4. Early assessment at Maine Yankee indicated that physical decommissioning work would not begin for 6 – 12 months in order to complete the business cases, develop and issue RFPs, obtain, evaluate and select contractors, and mobilize the contractors.

Maine Yankee then looked at this 6 – 12 month period as an opportunity to evaluate and conduct relatively discrete (defined scope) projects which would likely be required regardless of the contracting approach selected and would reduce the overall project risk. The discrete projects included site asbestos abatement, hot spot reduction, reactor coolant system decontamination, initial characterization surveys, and the transition of the power block to "cold and dark" status. The transition to "cold and dark" may either include the creation of a spent fuel pool island, or the spent fuel pool island creation may be a separate unique transition project.

Asbestos Abatement

During plant operations asbestos was remediated as needed to perform plant maintenance or modifications. As such, Maine Yankee had experience in contracting with appropriate asbestos remediation and disposition firms. No wholesale remediation occurred during operations. Asbestos was widely used at Maine Yankee in insulating material, fire deterrent, paint additives and in tile. This was similar to other reactors that began operations in the early 1970s. The volume of asbestos as provided in an earlier decommissioning cost estimate was 16,000 ft^3. Maine Yankee specific assessment was that approximately 28,500 ft^3 of asbestos would need remediation. It was estimated that approximately 1/3 of the asbestos was radioactively contaminated and would need disposition at a licensed low-level waste site. Non-asbestos insulation was left installed in the turbine hall to help facilitate re-powering options and/or the potential sale of turbine hall components.

The asbestos remediation project began in March 1998 and concluded in mid-December 1998. This abatement project was estimated to be at least four times larger than any asbestos abatement project ever completed in the State of Maine. It was also the largest abatement project ever performed by Maine Yankee's asbestos abatement subcontractors. The project utilized the services of over 12 subcontractors, at a peak of 145 workers, and they worked approximately 200,000 person-hours to remove ~80,000 ft^3 of asbestos containing materials.

Hot Spot Reduction

Maine Yankee viewed the reduction of radiation exposure for decommissioning as a significant objective for the overall project. Two early projects were initiated for the purpose of reducing the source term, or amount of radioactive material, in the plant to which decommissioning workers would be exposed. These two projects were Hot Spot Removal and Reactor Coolant System Decontamination.

Radiation surveys conducted during plant operation would note general hot spots in plant cubicles, pipe chases and other areas. These hot spots were often at piping elbows, valve connection points, locations in piping with flow changes, and other locations. In order to avoid unnecessary exposure to technicians, these areas were only generally located. The primary purpose of these surveys being to identify the general area of elevated exposure rates to notify workers to avoid the area.

The hot spot reduction program intended to specifically identify the hot spots to allow them to be "surgically" removed, that is cutting out the specific valve or piping section vs. removal of entire lines or components in an area.

In order to accomplish this program, the systems were drained and taken out of service. This meant that only systems no longer needed for the safe management of the fuel were available for the hot spot reduction. Maine Yankee obtained a gamma camera (Gamma Cam) to support the hot spot reduction effort. The Gamma Cam consisted of computer based video camera and radiation detection equipment. In use, the Gamma Cam would provide a black and white image of a monitored area with superimposed color areas. The color variations represent variations in radiation exposure rate. The images produced would allow clear identification of the highest activity sources in an area, which could then be removed. The process could be repeated for a given area to produce the desired dose reduction.

The site Radiation Protection Manager estimated that the hot spot reduction program likely reduced the total project exposure by ~ 150 person-rem (1.5 person-Sv).

Reactor Coolant System Decontamination

In addition to hot spot reduction, Maine Yankee also decided to perform a chemical decontamination of the reactor coolant system (RCS). The Radiation Protection Manager estimated that RCS decontamination also likely reduced the total project exposure by ~ 150 person-rem (1.5 person-Sv).

The subject of the RCS decontamination is addressed in detail in EPRI Report # TR-112092, Evaluation of the Decontamination of the Reactor Coolant Systems at Maine Yankee and Connecticut Yankee, and Report # 1003026, Decontamination of Reactor Systems and Containment Components for Disposal or Refurbishment and is summarized below.

The RCS decontamination contractor was selected to provide craft support, electrical services and waste processing services. Limited use of plant equipment was required. The reactor vessel was bypassed by the installation of a flow through nozzle dam assembly, called a spider, at the interface of the reactor coolant loops and the reactor pressure vessel. The steam generator tubes were bypassed by jumper and reduced flow rates (400 – 650 gpm) were used. Recirculation was provided by an external 600 gpm pump provided by the contractor. External heating, ion exchange vessels, chemical addition, sampling and filtration were also provided by the contractor.

The process included two separate applications or phases. Phase 1 included portions of RCS Loop 2 and 3, the letdown system, charging system, fill and drain system and pressurizer (Figure 3-1). Phase 2 included all three loops and the residual heat removal system (Figure 3-2). The process was begun on February 10, 1998 and was completed by March 7. This included two days to change over systems and two days for system clean-up at the end of the decontamination.

A total of 11 cycles were applied in Phase 1 requiring 191 hours. Phase 2 completed a total of 13 cycles in 182 hours. The results of the project included:

- 102 curies of gamma-emitting activity were removed (98% cobalt-60);
- 673 pounds of dissolved metals were removed (278 pounds of iron, 262 pounds of nickel, and 133 pounds of chromium);
- The decontamination factor (DF) over all points was 31, while the DF for points greater than 100 mR/h was 89; and,
- 535 ft^3 of ion exchange resin waste was generated from the decontamination with an additional 90 ft^3 of resin generated from the system deboration.

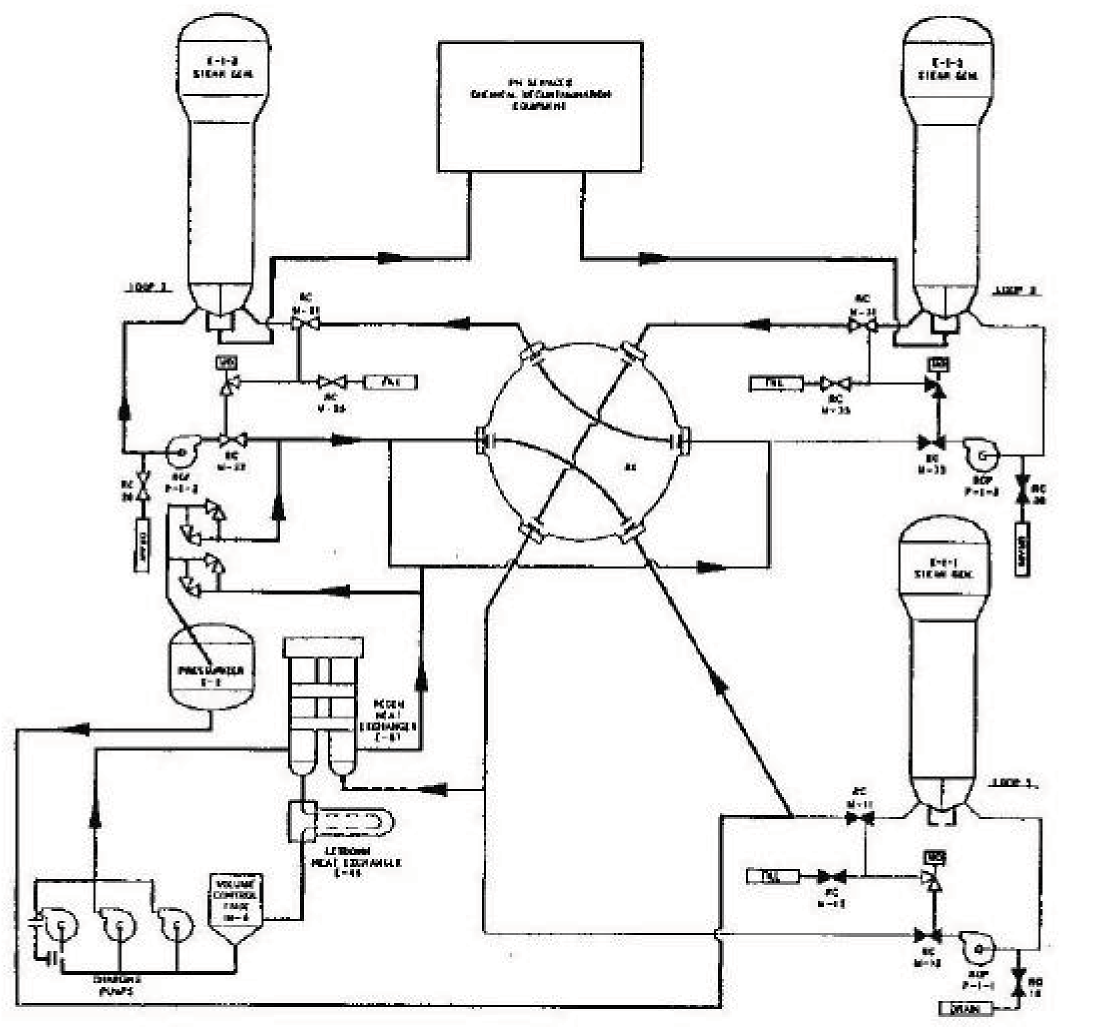


Figure 3-1 Maine Yankee RCS Decontamination Phase 1

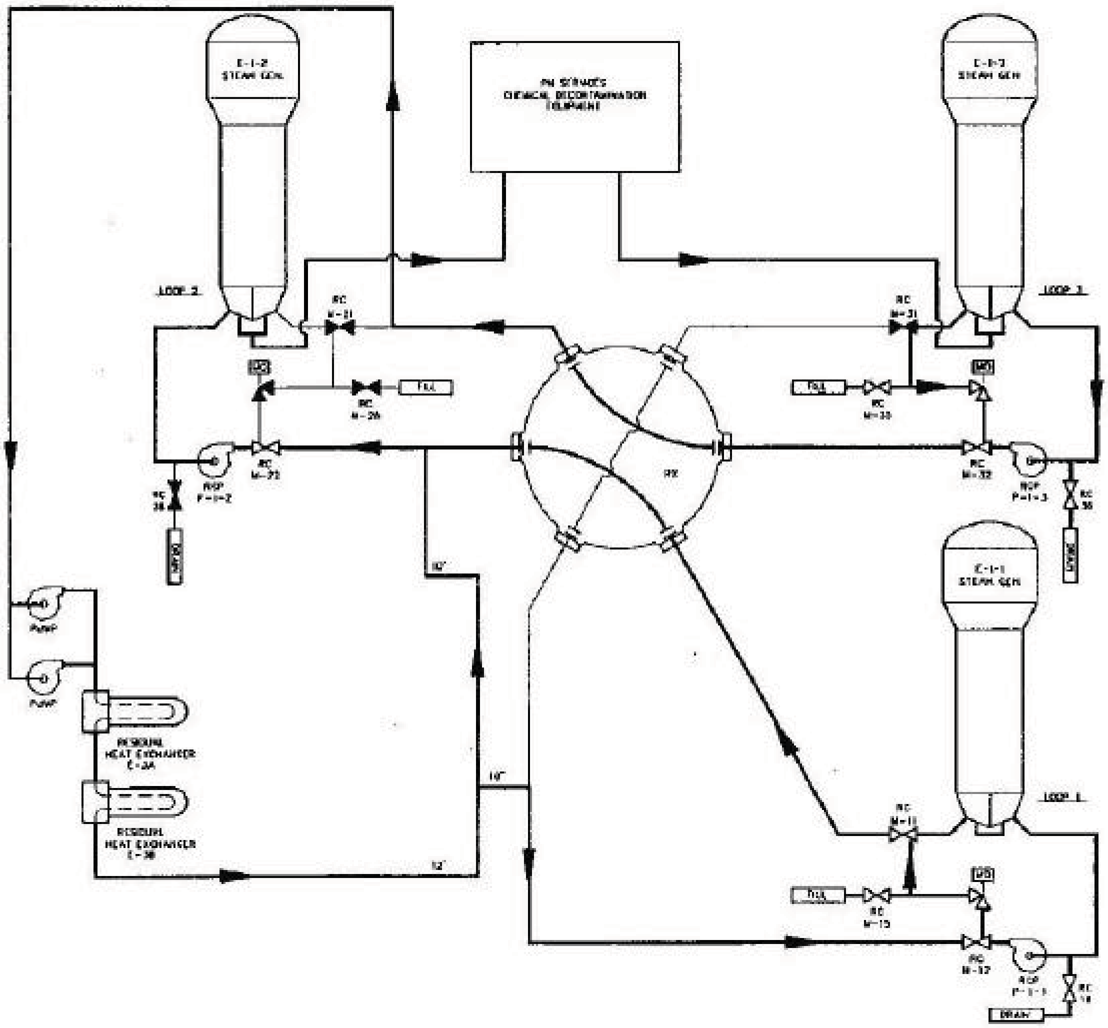


Figure 3-2 Maine Yankee RCS Decontamination Phase 2

Initial Characterization Surveys (ICS)

It was identified early on that a detailed site characterization would be essential for any decommissioning contract approach selected, as the results of site characterization support the development of detailed project plans. A site characterization contractor was selected and began site work in mid-October 1997 and completed in April 1998 with the report issued April 29, 1998. This characterization included hazardous materials as well as radioactive materials.

An interesting aspect to this project was the participation by prospective DOC bidders. Maine Yankee had decided to proceed with preparing an RFP for a DOC under a fixed-price approach. The expectation from Maine Yankee was that the DOC selected would be responsible for required remediation of contaminated materials. It was imperative therefore that the prospective bidders accept the results of the initial site characterization as their bids would in-part be based on the amount of material to remediate.

In the event that contaminated material was subsequently found that was unidentified in the initial site characterization, typical industry practice would be for the general contractor to state this was outside the initial project scope, hence would require additional cost to remediate. Maine Yankee wanted to avoid this possibility, so the prospective DOC bidders became participants in the characterization project. They reviewed the planned scope of work, suggested changes or additional areas to assess based on their experience. Each bidder provided one or two persons onsite at Maine Yankee for the duration of the characterization project at their own cost. At the conclusion, each prospective bidder was bound by the same characterization results.

In all, approximately 130,000 site measurements were taken and nearly 800 samples for laboratory analysis were taken. Interesting results include:

- Large background variations were noted across the site based on varying depths of bedrock, mineral deposition and other factors.
- Characterization found contamination in the carpet of the former visitor center – later determined to be from a piece of uranium ore used in demonstrations.
- The only real anomalous environmental result was an area at Bailey Point located south of the plant (Figure 1-3) approximately 10 ft^2 and 6 in. deep (which was remediated).
- Two marine sediment samples showed elevated levels of volatile organic compounds (VOCs) and semi-volatile organic compounds (SVOCs) – presumed to be likely petroleum products which originated from building roofs and the parking lots.

Cold and Dark

Maine Yankee intended to proceed with a cold and dark approach for its systems and buildings. "Cold and Dark" is a phrase used to describe a facility in which virtually all liquid containing systems have been drained, and electrical power to components has been removed. The other primary alternative is to drain/de-energize systems on a schedule to match the decommissioning required. Maine Yankee decided to on the Cold and Dark approach rather than other options based on their determination that the Cold and Dark approach would:

- Provide the greatest level of nuclear security (once the spent fuel was properly isolated) by draining and de-energizing systems which could interact with the spent fuel pool;
- Provide the greatest level of industrial safety by ensuring that all energy sources were removed prior to personnel beginning decontamination or dismantlement activities; and,
- The Cold and Dark approach would be the simplest one for prospective DOC bidders to evaluate and to bid on and would likely result in a lower bid from the prospective DOCs.

Placing the plant into a cold and dark condition was accomplished with four major initiatives:

- Spent fuel pool island project (SFPI);
- System evaluation and reclassification team (SERT);
- Control room transition (CRT); and,

- Cold and dark projects

As long as spent fuel was retained in the spent fuel pool, its control and isolation was the nuclear safety focus for the project. In order to allow for decontamination and dismantlement activities to occur, the spent fuel pool must be isolated from the rest of the plant by isolating piping, electrical and control systems. This isolation of the spent fuel pool and its supporting structures from the planned decommissioning activities required the creation of a SFPI. The SFPI required the installation of an independent spent fuel pool cooling system, new electrical distribution system, new control room (away from the decommissioning area), new HVAC and radiation monitoring systems and a collapsed security boundary.

The SERT evaluated all structures, systems and components (SSC) on the site. The initial SSC list was based on the equipment and components required per the operating license. The SSC were then evaluated against the following criteria:

- Was the SSC used to prevent or mitigate the design basis accident for the permanently defueled condition;
- Was the SSC needed for the safe storage of radioactive wastes or spent fuel;
- Was the SSC needed to satisfy the plant design, licensing basis or technical specifications for the permanently defueled condition; or,
- Was the SSC needed for day-to-day plant operations during decommissioning?

Based on this evaluation each SSC was then categorized as either "available" or "ready to be abandoned".

One result of the SFPI and SERT projects was the determination of what control and instrumentation would be needed for the decommissioning effort. This level of control and instrumentation is greatly reduced in decommissioning from that required during operations. Rather than maintain the existing operating control room using only the reduced number of controls and instruments, Maine Yankee decided to provide a completely new control room for the decommissioning effort.

The control room transition required the relocation of all alarms to the new control room. It also provided for the movement of all fire detection and suppression controls and indicators to the control room. Applicable data from the site meteorological tower was also routed to the new control room. This smaller scope control room allowed operators to more readily focus on the fewer number of critical parameters and instruments. The new control room also allowed the de-energization and dismantlement of the former operating control room.

The remaining actions in the "Cold and Dark projects" included:

- Changes to mechanical facilities;
- Changes to electrical facilities;
- Waste minimization;

- Relocation of staff;
- Initiation of the "orange plan"; and,
- Changes to fire suppression systems.

The changes to mechanical facilities provided for a relocated health physics checkpoint, and the reconfiguration of radiologically controlled area ventilation, plant sumps and drains, and site wells and potable water.

The changes in electrical facilities separated the "going forward" electrical system from the existing plant electrical distribution system. It included the repowering of essential loads (cranes, buildings to stay occupied, ventilation and construction power). Lastly it involved the reconfiguration of the external power lines feeding the plant.

Waste minimization involved removal of all unneeded chemical and oil products from the site, as well as the closure of plant sumps and redirection of water sources. Tanks were cleaned and systems were drained. Plant batteries, mercury and any chlorofluorocarbons (CFCs) were appropriately removed from site.

Staff relocation was an early challenge to the project which continued through project completion. Plant permanent staff numbers were reduced over the course of the project and numbers of contractor personnel varied widely over the project. For each aspect of the decommissioning project, appropriate office and shop space was required. Changes in telecommunications and computer services continued on virtually a daily basis throughout the project. Assuring sufficient potable water and sanitation services for the fluctuating staffing levels throughout the project also posed challenges for Maine Yankee.

Once the SERT, SFPI and mechanical and electrical facilities changes were completed, the plant was left with a relatively small set of required structures, systems, components, controls and instrumentation. It was essential that these components not be impacted by decommissioning activities. A simple method was needed to identify these components so that project personnel (Maine Yankee and contracted personnel) would not alter, or manipulate them. The "orange plan" was established for this purpose. All of these essential components were tagged with orange ribbon. All project personnel were trained to not touch orange components unless under a proper work plan. This was a good approach to communicate those remaining safety significant systems, but it is important to identify all portions of the selected systems including control and instrument cabling.

Changes in the plant fire suppression programs involved the reduction of fire loads (reduced combustibles) and a modification to the fire fighting plan and procedures to allow the draining of water-based fire systems in unheated areas and transition to dry-pipe based fire suppression systems. Appropriate changes in plant personnel training was also performed on the need to control fire loading and to provide adequate portable fire suppression (fire extinguishers).

Transition Human Resources

Beginning in the summer of 1997 and continuing into the decommissioning transition, plant staff was understandably operating with a great deal of personal uncertainly. Whether or not they would continue to be employed at the Maine Yankee site or by what company was an ongoing concern. Through this period and into the decommissioning, Maine Yankee Human Resources personnel worked to continue communications to the workforce to maintain morale and continued worker focus on the tasks at hand.

The biggest change is the cultural shift from operations to shutdown. "How does this affect me, how does this affect my job, my family, my relocation options, etc." The employees wanted specific answers, and Maine Yankee tried to provide specific answers, but in some cases management didn't yet know the answers. It was most important to maintain ongoing communications.

Maine Yankee wanted to provide some level of comfort to plant staff who were working under this level of uncertainty. One manner in which this was addressed was the issuance of a severance and early retirement program. The program was generally comparable to others from New England utilities and was on the order of two weeks of pay for every year of service with the utility. If you stayed on the project as long as the company wanted you to stay, then you qualified for a severance benefit. This gave the Maine Yankee employees a measure of financial comfort.

This program didn't change after the final shutdown and was viewed to be very important to help maintain employee trust and confidence, particularly to those who were asked to stay until the project ended.

As decommissioning planning continued, it became clearer as to the skills and quantities of skills needed from the Maine Yankee staff. Maine Yankee staffing targets were developed based on presumed DOC staffing and was projected to be:

- Final Shutdown ~ 600
- End of 1997 ~ 300
- End of 1998 ~ 135
- End of 1999 through completion of fuel transfer out of pool ~ 85

These numbers reflected the Maine Yankee staffing only and not any DOC contracted personnel.

After fuel transfer to dry storage was completed the staffing would drop as additional buildings were demolished until it would reach approximately 20 after the completion of the final termination surveys. As future staffing levels were determined, employees would be provided with their individual end date of employment. Initially, group meetings were held to discuss general staffing approaches and project plans. These were followed by department specific meetings and ultimately individual meetings between employee and supervisor. These staffing projections and end dates were revisited every three to six months. Meetings between individual

and supervisor were then held to update the site staff for their particular end dates. These meetings served a valuable purpose in that plant staff continued to have clear individual end dates for the project. This minimized staff uncertainty which helped staff maintain focus on the project, rather than personal circumstances.

The union had a different severance program (but similar concept) which was in place through the existing contract. Approximately two years after the shutdown the union contract was renegotiated due to the contract expiring, irrespective of the decommissioning. In the new contract, changes were made to accommodate the changes from decommissioning including cross-training and qualifications of union personnel. This similarly reduced individual uncertainty for union personnel providing for project focus.

Maine Yankee also established a retention program primarily for key employees. The key employees were determined on a proceduralized basis and was reviewed by the CEO and CFO typically with the appropriate vice president to determine the positions most needed and when needed (for what duration). This retention program provided a certain percentage of the individual's annual salary per month the individual stayed with the project, assuming they stayed as long as Maine Yankee needed them. If individuals left prior to their agreed to end date, they forfeited their retention bonus.

This program was initially targeted for relatively few individuals, however as the project continued, two additional phases of the program were initiated. In each phase the number of individuals under the program increased. This overall increase was due to two primary reasons. The first being that as the project proceeded, the critical expertise and experience changed, requiring a review of the critical skilled needing to be retained. Secondly, as the project continued and Maine Yankee staffing continued to shrink, the relative contributions of each remaining employee became more significant to the project overall. It is therefore essential to develop a broad and robust retention program early on in a decommissioning project, but equally important to review the skill sets needed to be included in the program on a periodic basis throughout the project.

Transition Stakeholder Interaction

One of the tasks initiated during the pre-shutdown period was discussion with the State Senator from Lincoln County regarding the need for a new method for Maine Yankee to communicate with and receive input from the local community and stakeholders. This was viewed to be needed whether the site was sold or decommissioned.

One outcome of these discussions was the development of the Community Advisory Panel (CAP). The CAP is addressed in more detail in Section 6.

The first CAP meeting was held just two weeks after the shutdown decision was announced. At the writing of this document, CAP had held nearly 50 public meetings on the Maine Yankee Decommissioning project.

4
USE OF DECOMMISSIONING OPERATIONS CONTRACTOR

Lessons Learned/Recommendations

- Understand the strength of your primary contracting partner(s) both technically and financially.
- Have sufficient contract provisions that in the event of major contractor problems that provides the owner with options to effectively and safely continue the project.
- Keep or obtain the best people for the project. Often these will not be all within one organization or company.
- If you have the radiological, licensing and deconstruction expertise, it may well be reasonable and cost effective to self perform the decommissioning.

Overview

When Maine Yankee ended operations, many things in the utility industry were occurring that influenced the decommissioning contracting approach selected by Maine Yankee.

The last group of large power plants built (in the 1980's) tended to be built under traditional general contractor time and material (T&M) contracts. For several reasons, the total costs for these contracts often greatly exceeded the original estimate/budget. Maine Yankee didn't want to deconstruct the plant under the same economic model, so it pursued the fixed price contract. The decommissioning trust funds also provided a finite sum of money allotted to the project. This also supported the decision to pursue a fixed price contract.

The approach taken by Maine Yankee was that the DOC RFP was designed to shift some of the project risks to another entity that would be qualified to perform the work safely. This shift of risk was addressed in a presentation during the December 1998 EPRI Decommissioning workshop (EPRI TR-111025). The following table is derived from material in this presentation.

Table 4-1 Risk Ownership for DOC vs. Non-DOC

Task	DOC	Non-DOC
Transition management	Contractor or owner	Owner
Project management	DOC	Owner
Site management	DOC	Owner
Site Labor management	DOC	Various
Cold & Dark preparations	DOC	Owner/contractors
Primary system decon	Owner/contractor	Owner/contractor
Site characterization	Owner/contractor	Owner/contractor
Large component removal	DOC	Contractor
Commodity removal	DOC	Contractor
Waste packaging, shipping and disposal	DOC	Contractor
Licensing	Owner/DOC	Owner/contractor
Health physics	DOC	Owner/contractor
Station administration	DOC	Owner/contractor
Procurement	DOC	Owner/contractor
Fuel handling	DOC	Owner
Fuel storage facility	DOC	Owner/contractor
Final status survey	DOC	Owner/contractor
Asset recovery	Owner/DOC	Owner
Repowering	DOC	Owner

In addition to the discussion of risk transfer, the presentation addressed the perceived advantages and disadvantages of the use of a DOC and provided a listing of required strengths of potential DOCs and activities viewed by the DOC as necessary prior to contract award.

DOC Advantages

- One constructor/contractor for owner to deal with
- Fixed price
- Stronger commitment to schedule
- Shared risks
- Union concessions
- Work scope synergies
- Retraining and reuse of selected site personnel
- PUC/FERC acceptance based on presumed fixed cost for decommissioning
- Advantages available from lessons learned
- Savings for owner

DOC disadvantages

- Up front characterization and bid cycle time
- Loss of owner control
- Owner pays for unused contingencies
- Potential cost of changes beyond contract

DOC required strengths

- Large plant management capability
- Nuclear licensing
- Safety evaluations
- Nuclear engineering/mechanical design
- Contaminated equipment removal/disposal
- ISFSI casks/shipping containers/crane evalations
- Procurement/contractor management
- Construction labor/union management
- Radiological analysis/design/planning
- Plant systems understanding
- Decommissioning process optimization capability
- State and Local regulatory agency licensing capabilities

Prerequisites to DOC contract

- Site characterization
- Cold & dark strategy
- Fuel storage strategy
- Primary side decontamination
- Site plant data/drawing package

In addition to the selection of a DOC, Maine Yankee also had a decision to make regarding the Maine Yankee management. Earlier in 1997, Maine Yankee had contracted with Entergy Nuclear, Inc. (ENI) to provide management services to the plant. This was part of the efforts taken to restart the plant and institute comprehensive site improvement plans. Several of the key Maine Yankee managers at the time of permanent shutdown were actually employees of ENI.

In November 1997, it was announced that Maine Yankee had amended the contract with ENI to continue its management services in the conduct of the decommissioning project. A management contract with ENI has continued to the present.

Selection of DOC

Maine Yankee issued the RFP for the DOC on April 17, 1998 with bids due by May 29, 1998. The RFP included certain options for the bidders including repowering the site, spent fuel management/storage, and meeting a 15 mrem/y + ALARA release criteria.

Initially Maine Yankee had approximately 6 bidders on the project, who were generally large leader companies with smaller subcontractors jointly bidding on the job. An initial critical review was performed of the submitted bids to determine if the bidder fully met the bid qualifications and requirements. After this initial review, detailed bid reviews were performed.

The bid evaluation was conducted by Maine Yankee and a team of third party experts. The experts included financial analysts, low-level waste experts, general contracting, and repowering experts. Based on request by the CAP, an expert in economic redevelopment also participated in the bid review process. The bid evaluation used a structured decision analysis process which was weighted on factors significant to successful decommissioning. The options in the bids were evaluated against the most competitive base bid.

The bid evaluation criteria included:

- Safety history (industrial and radiological);
- Experience in nuclear environment;
- Experience on similar deconstruction projects;
- Qualifications/credentials of key personnel;

- Bidder financial condition including credit rating; and,
- Innovation of decommissioning approach.

Maine Yankee received very competitive bids, in part because it was believed that there would be a near term market for firms with large decommissioning project experience. The successful bidder would be viewed as having a competitive advantage for future decommissioning projects.

On August 4, 1998, Stone & Webster Engineering Corporation (SWEC) was awarded the first turnkey, fixed-price contract where the contractor takes the financial risk for executing the decommissioning project. The SWEC contract was for a total of ~ $250 million of a total estimated decommissioning cost of $541 million (1998 dollars).

Several provisions in the contract eventually proved particularly useful to Maine Yankee. These include:

- The contracts between subcontractors and the DOC could be assumed by Maine Yankee on the same terms and conditions without new contracts being let.
- A substantial amount of performance and payment bonds were specified in the contract with the DOC
- Very tight financial controls were mandated in the contract including review of DOC payments to all subcontractors on the job.
- There were contract provisions that if the DOC became financially insolvent, that the contract could be terminated

The primary financial management system used between Maine Yankee and the DOC dealt with “earned value”. Earned value was used in both labor and service contracts and for the project as a whole. The original concept was to tie all project elements as designed in the work breakdown structure (WBS elements) to each WBS element’s budget and the respective payment to the DOC.

Each work task was assigned a particular budget (money or labor hours). Progress on each work task then drove payments to the DOC. An example is noted below for the licensing of the spent fuel cask system.

WORK PACKAGE PERCENT COMPLETE - WPPC
FORM 1

PMP 11.0 FORM1

PROJECT: MAINE YANKEE DECOMMISSIONING

WORK PACKAGE NO. **J.C.D.ISFS.0065** Activity # **ISFSI65**

WORK PACKAGE DESCRIPTION:
Cask Vendor Licensing

EARNED VALUE BREAKDOWN

	Cask Vendor Licensing Activity	% OF TOTAL	COMPLETE	EARNED	MY APPROVAL
1	1032 negotiate cask vendor contract	2.0%	Y	2.00%	RCH
2	1085 Prel eval of MY non-std Fuel	3.0%	Y	3.00%	PP
3	1096 Validate Design with drop test	4.0%	Y	4.00%	RCH
4	0008I perform storage source term analysis	2.0%	Y	2.00%	RCH
5	0024I perform transport source term analysis	2.0%	Y	2.00%	RCH
6	0005I perform storage criticality analysis	3.0%	Y	3.00%	RCH
7	0022I perform transport criticality analysis	3.0%	Y	3.00%	RCH
8	0026I perform transport shielding analysis	3.0%	Y	3.00%	PP
9	0028I perform transport thermal analysis	2.0%	Y	2.00%	RCH
10	0010I perform storage shielding analysis	3.0%	Y	3.00%	PP
11	0014I perform site dose analysis	2.0%	Y	2.00%	PP
12	1059 prep/submit amendment for storage non std fuel	10.0%	Y	10.00%	PP
13	1064 prep/submit supp/ for transport non std fuel	5.0%	Y	5.00%	RCH
14	0016I perform storage thermal analysis	2.0%	Y	2.00%	RCH
15	0019I perform storage structural analysis	2.0%	Y	2.00%	RCH
16	0030I perform transport structural analysis	2.0%	Y	2.00%	RCH
17	1140 NRC review amentment non-std fuel storage	4.0%	Y	4.00%	PP
18	1155 NRC review Amendment for fuel Transp	3.0%	Y	3.00%	PP
19	1065 Receive RAI for fuel transp	1.0%	Y	1.00%	PP
20	1066 Respond to RAI Fuel Transp	4.0%	Y	4.00%	PP
21	1060 Receive RAI non std fuel storage	1.0%	Y	1.00%	PP
22	1062 Respond to RAI on Non-std Fuel Storage	7.0%	Y	7.00%	CO
23	1146 NRC Rev 1st Round Resp Fuel Transp	1.0%	Y	1.00%	PP
24	1137 NRC Review RAI Response Non-std Fuel Storage	2.0%	Y	2.00%	PP
25	1055 NRC Issue Transport CoC	4.0%	Y	4.00%	PP
26	1067 NRC issue draft SER(Non Std Fuel)	10.0%	Y	10.00%	PP
27	1068 Rule making on Amended Storage CoC	3.0%	Y	3.00%	PP
28	1134 Receive Amended CoC non std fuel Storage & Transp	10.0%	Partial	7.58%	DR
TOTAL		100.0%		97.583%	

Figure 4-1 Example of Earned Value Report

In the figure above, the first activity, "Negotiate cask vendor contract" was evaluated to require two percent of the effort required for the overall work package "Cask vendor licensing" to be completed. Once the specific task was complete and approved by Maine Yankee, the contractor would have been deemed to have earned two percent of the fees associated with the work package. Using this process provided direct contractor compensation to match the project management work plans and schedule.

DOC Removal and Transition to Self-Performance

In the latter part of 1999, Maine Yankee began to receive complaints from the DOC subcontractors that they were not receiving timely payments from the DOC. In addition, reports in industry trade journals suggested that some other DOC projects (primarily overseas) were experiencing problems which could adversely affect the DOC's financial condition.

In early 2000, work activities at Maine Yankee also began to have some problems. One cause of the problems was perceived to be a lack of resources applied by the DOC to the project. These problems resulted in meetings between senior management at Maine Yankee and the DOC. After these meetings between MY and the DOC, the contractual financial controls were tightened by contract amendment. This included a further DOC parent company guarantee.

In late 1999, the DOC also began an effort to sell certain corporate assets. In April 2000, the DOC had to restate previous corporate earnings. On May 4, 2000 Maine Yankee terminated the DOC contract based on performance issues with the contract including contractor insolvency provisions. Less than a week later, the DOC announced that it would file for corporate reorganization under Chapter 11 of the U.S. bankruptcy code.

In order to continue project activities smoothly, a separate interim contract was issued to the DOC for the period from May 4, 2000 through June 30, 2000. This provided a time period for Maine Yankee to take over direct management of the project rather than just the project oversight. Maine Yankee began serving as the DOC (so called "self-performing) effective July 1, 2000. During this period Maine Yankee made the decision to stop work on some non-critical path tasks that could be easily done once the contract issues were sorted out and focused on keeping the critical path work moving forward.

A near-term action after the DOC was terminated was the review of all subcontracts to determine those that would stay in place. The objective at the time was to avoid if possible, the costs of demobilization of current contractors and mobilization of any new contractors. As noted earlier, most subcontracts were directly assignable to Maine Yankee. This made the transition much easier as the time could be spent determining the subcontractors to retain, without the need for obtaining new contracts with each subcontractor.

This interim period also allowed Maine Yankee to issue an RFP for a new DOC. Essentially Maine Yankee invited bidders to "step into the DOC's shoes to finish the project". The Maine Yankee intent was for the subsequent DOC to also perform to a fixed price contract.

In the time between the initial DOC contract and the time of contract termination, the market had changed substantially. No longer was there an expectation that there would be a large number of nuclear plant closures. Secondly, there were a lot of lessons from the Maine Yankee experience to the industry as to how complex decommissioning projects really were.

The bids submitted to Maine Yankee were of a "fixed-price nature", but not as comprehensive in scope or as fixed a price as Maine Yankee would have hoped. The Maine Yankee management team wanted to continue with the approach (fixed price) used with the former DOC, but the bidders took a larger number of exceptions with the RFP, to protect themselves. The risk sharing equation shifted for this bid back toward Maine Yankee.

Maine Yankee began the management of the decommissioning activities on July 1, 2000 with a focus primarily on the dry cask storage system implementation and reactor vessel internals segmentation. These two major tasks were the primary drivers of the overall project critical path. Maine Yankee personnel assured that these two tasks continued, as others were allowed to slip in schedule or were deferred entirely until the project management issue had final resolution.

During this period, Maine Yankee gained experience with project management and completed the assumption of the former DOC subcontracts it felt appropriate to continue. In addition to the new DOC bids, Maine Yankee prepared a bid itself to provide to the Board of Directors.

In January 2001, the Board of Directors directed Maine Yankee to continue the management of the overall project through its completion. Maine Yankee continues the management of the project currently and will complete the project early in 2005.

5
FUEL STORAGE OPTIONS

Lessons Learned/Recommendations

- It clearly would have been preferable to have an operational Independent Spent Fuel Storage Installation (ISFSI) prior to beginning decontamination and demolition. Significant time and legal interaction was necessary to secure a state permit for the facility. Substantial engineering work was required to assure Spent Fuel Pool Island (SFPI) safety while decommissioning occurred. Decommissioning is a much simpler project when fuel is fully out of the pool before physical decontamination or dismantlement begins
- Plants with any history of fuel damage should prepare special contingency plans in case fuel pellets or other damage is found during final fuel inspection. Maine Yankee evaluated both radiological and safeguards issues to see what options would be available for storage in other locations than a Dry Cask Storage (DCS) canister.
- Evaluate other special sources that may exist onsite, e.g., plutonium-beryllium (Pu-Be) or americium-beryllium start-up sources, boronometers or other similar Greater Than Class C (GTCC) materials. Maine Yankee ultimately applied to the DOE orphan source program. It took about four years to get DOE to take the source. You need to evaluate whether the selected spent fuel cask system can store the sources for future disposal. Maine Yankee got an early legal opinion that the Pu-Be source was not "associated with the fuel" so couldn't put into a cask. A sound knowledge base for all items in the spent fuel pool and recent inspection of each is vital before proceeding with a comprehensive dry storage plan.
- Even though shutdown, it is important to maintain good fuel pool chemistry to support fuel handling and transfer operations.

Introduction

In the Maine Yankee PSDAR, dry cask storage (DCS) was assumed for planning purposes. The fact hat DCS was an approach for planning only, was reiterated in the PSDAR public meeting in November 1997. It was presumed at that time that the DOE would not begin accepting spent fuel in accordance with its contract with Maine Yankee and that some form of interim storage would be required.

The DOC RFP required the bidders to submit approaches for interim onsite fuel and Greater Than Class C (GTCC) waste storage. The DOC bidders generally teamed with existing providers of DCS systems and included DCS in their bids as one of the contract options to Maine Yankee.

In the first meeting of the Community Advisory Panel in late August 1997, Maine Yankee management stated that initially, Maine Yankee would modify the existing spent fuel pool support systems to allow decommissioning to begin and that the longer term storage approach (wet vs. dry), had not yet been decided. These discussions continued with the CAP until nearly the middle of 1999.

Spent Fuel Pool Island (SFPI)

Similar to several other permanently shutdown power reactors, Maine Yankee initially opted to modify the existing spent fuel pool support systems for storage of spent nuclear fuel until an approach could be selected which would provide for safe storage of fuel until the DOE fulfilled its contractual obligations and removed the spent fuel and GTCC materials.

These modifications typically provide self contained fuel pool cooling and cleanup systems as well as monitoring, controls and electrical power. These modifications effectively isolate the spent fuel pool from the remainder of the plant structures, systems and components forming a "nuclear island". This approach allows decommissioning to begin on the remainder of the plant while the fuel is safely maintained. EPRI report # 10003424, Spent Fuel Pool Cooling and Cleanup Systems – Experience at Decommissioning Plants, provides a summary of a number of shutdown power reactors who have stored fuel in this manner. The information and figure below are excerpts from this document.

The Maine Yankee SFPI used two separate pool cooling loops using an intermediate cooling loop to exchange heat with air-cooling fan units. It used a single spent fuel pool heat exchanger. The lowest piping connection in the system was located above the top of the fuel assemblies to preclude a siphon event from uncovering the spent fuel. Backup power was provided by a dedicated diesel generator which was not specifically required by license requirements or accident analysis.

The spent fuel pool cooling and intermediate loops were located in the spent fuel pool building. The fan powered air coolers were located outside adjacent to the spent fuel pool building. The cooling loops were designed for a maximum pool heat load of 3.3E6 BTU per hour and a maximum heat up rate without cooling of 1.08 degrees Fahrenheit per hour.

The cleanup system consisted of surface skimmers feeding a single purification pump. The water was then filtered with a 0.2 micron pre-filter and a 6 micron post-filter. Further cleanup was provided by an in-pool 28 ft^3 mixed bed demineralizer with an internal pump and motor to circulate the pool water.

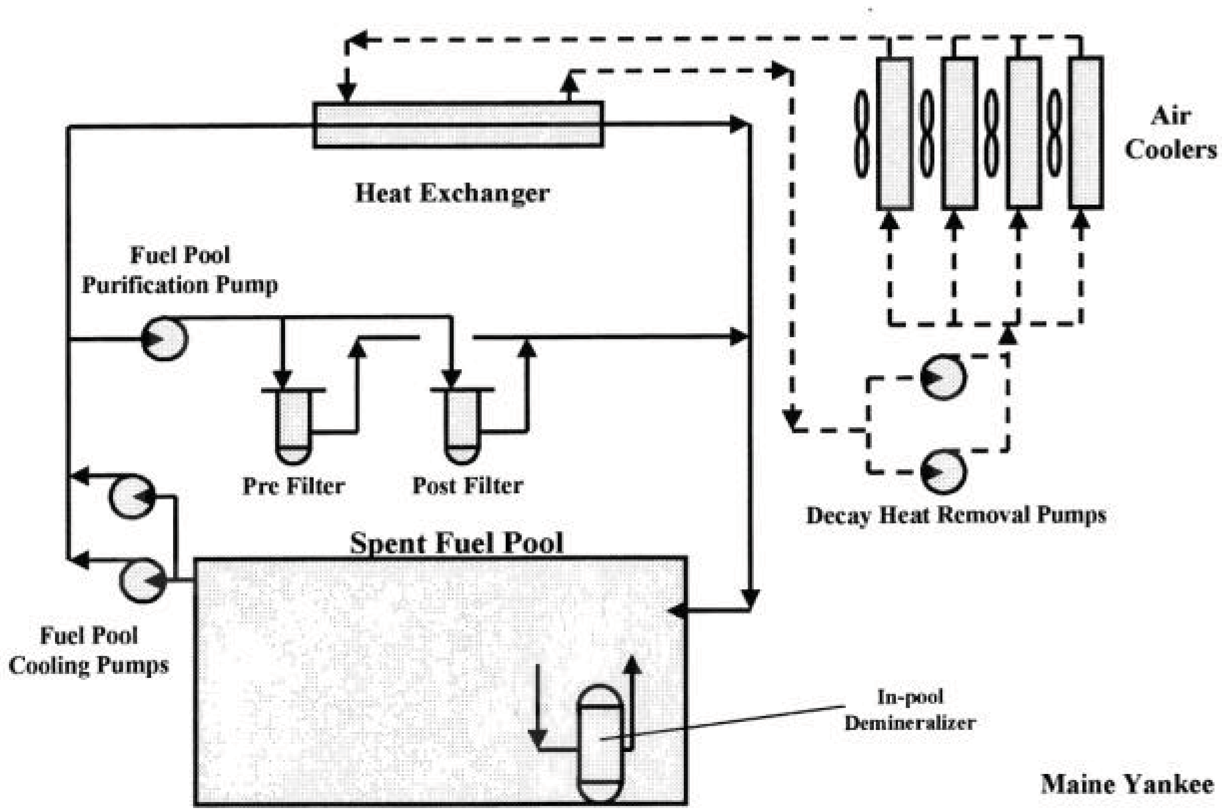


Figure 5-1 Simplified Maine Yankee SFPI Schematic

Parameters monitored in the SFPI included:

- Pool water temperature, level and boron concentration;
- Cooling and purification system temperature, pressure, radiation levels, and makeup capability; and,
- Fuel Pool Building radiation levels, ventilation flows, sump levels and fire detection.

In May 1998, the SFPI became operational with an unexpected problem which led to substantial stakeholder interaction. The fans used for air cooling the intermediate heat exchanger would operate at all times, and as sound surveys later showed, they increased the ambient noise levels at distances of up to one mile from the site by 10 decibels (DBA).

The increased noise levels were cause for substantial concern to the plant neighbors and other local residents. The Maine Yankee Public Affairs Director began receiving a number of calls asking when the noise would end. The correct answer of "about five years" was certainly not what the public would want to hear.

This challenge actually posed an early opportunity for a Community Advisory Panel (CAP) success. The CAP process provided a ready vehicle to frequently gather community input and for Maine Yankee to address the public. The meeting of June 24, 1998 was very well attended

with much input from the public on the issue. Based on the number of community complaints, Maine Yankee was able to announce at the CAP meeting that options were being evaluated to reduce the noise including fan motor replacement or construction of acoustic barriers.

By the July 1998 CAP meeting, Maine Yankee had determined that the only viable solution was to replace the fans with quieter ones. This modification, which cost approximately $160,000 couldn't be implemented until after the end of summer, due to the quieter fans being less effective at exchanging heat. The cooler fall – winter weather and lower spent fuel heat load due to fuel decay would allow use of the quieter fan motors. The modifications were completed in September of 1998.

The SPFI continued to operate successfully thereafter until the completion of the transfer of all spent fuel and fuel pool components to alternate storage or disposition.

Selection of Fuel Storage Approach

One of the business cases that is routinely performed early in the decommissioning process is the evaluation of long term fuel storage options. The storage period in question is the time between final shutdown and the expected time for DOE to complete the transfer of spent fuel and GTCC wastes from the site. This case typically becomes a decision between storage in a spent fuel pool island or a dry cask system (DCS), usually referred to as a "wet vs. dry" analysis.

The wet vs. dry analysis is relatively straight forward. Maine Yankee used the following inputs for their analysis:

- Financial inputs
  - Annual operating cost (all factored for inflation and discount rates)
    - Wages
    - Taxes
    - Utilities
    - NRC fees
  - Capital expenditures (cost of casks, canisters, ISFSI construction, modifications to spent fuel pool)
  - Decommissioning impact cost
- Risk Analysis – Time dependent issues
  - DOE not taking fuel by 2023
  - Cask fabrication delays
  - Cask licensing delays

The inputs were developed for each type of storage over the projected period of time that fuel was anticipated to be onsite. Variations on each input parameter are used to determine which

factor(s) provide the greatest impact to the decision. The primary driver is the expected year in which fuel transfer will be completed. This is because typically, wet storage requires a lower capital expenditure than dry storage, but requires higher annual operating and maintenance costs than dry storage. The results of Maine Yankee's analysis resulted in DCS being economically preferred, provided that the DOE would not fully remove spent earlier than 2019.

Once the original DOC bids were reviewed, additional information for the analysis became known; namely that the capital costs of DCS were higher than Maine Yankee's original assessment, and based on the overall integrated project schedules provided, the use of wet storage precluded decommissioning completion within seven years as targeted.

The selection of fuel storage approach can be solely made on technical and economic parameters, however Maine Yankee chose to also include stakeholder input into the fuel storage selection decision. This approach of obtaining stakeholder input at critical project milestones became the common practice throughout the Maine Yankee project.

In March 1998, Maine Yankee began the detailed discussion of fuel storage with the CAP and indicated that it wanted CAP and community input on the decision. At this CAP meeting Maine Yankee suggested that capital costs for DCS were approximately $40 - $50 million and would require 45 – 65 casks depending upon the cask design chosen. Operating costs were projected to be $40 million over the period of 2003 – 2023. Similar discussions were also held with the governor and other elected officials.

In order to gather community input on the decision, Maine Yankee conducted a public opinion poll on DCS issues. This was conducted in the April of 1998 with approximately 800 people. The results showed Maine Yankee and the CAP that any spent fuel storage option selected would require substantial public education. In order to better educate the CAP members, they traveled to existing dry cask storage facilities at three power reactors (two operating and one shutdown). Fuel storage was a continuing topic at the approximately monthly CAP meetings for several months. This communication effort led ultimately to the CAP stating in June 1999 that if spent fuel had to remain onsite for an interim period, that they preferred the DCS approach.

Dry Cask Storage Activities

The primary tasks for the dry cask storage project were to procure the appropriate number of fuel storage casks and to construct an appropriate storage location or pad upon which the filled fuel storage casks would be placed. The storage pad is typically referred to as an ISFSI pad (Independent Spent Fuel Storage Installation pad).

Siting and construction of the ISFSI pad presented another opportunity in stakeholder interaction. This is discussed in Section 6. The dry cask storage system provider that teamed with the DOC was NAC International. The selected cask system was the NAC-UMS Transportable Storage Canister (TSC) system, a multi-purpose canister system designed to contain 24 spent fuel assemblies. At the time of selection the vendor had not yet received certification by the NRC.

The DOC subcontract with the cask provider was to provide hardware only. The DOC intended to perform the cask loading in the spent fuel pool and transfer the loaded casks to the ISFSI pad. The DOC was also to construct the ISFSI pad. At the time that the DOC contract was cancelled, the ISFSI pad had not been built. Maine Yankee subsequently contracted for its construction (for an estimated contract value of $6.5 million). Maine Yankee also took over the DOC subcontract with the fuel cask provider in May 2000 and in late 2000 extended the scope to include fuel transfer activities.

The loading and transfer of Greater Than Class C (GTCC) materials (a total of four canisters) to the ISFSI pad began in January 2002. On August 24, 2002, Maine Yankee, with assistance from their cask contractor, transferred the first of 60 spent fuel canisters for storage at their ISFSI. After loading the canister with spent fuel, a shield lid was welded on and the canister was pressure-tested, dewatered, and vacuum dried. The canister was then backfilled with helium, the vent and drain ports were sealed, the canister was leak-tested, and a structural lid was welded onto the canister. The canister was then placed into a vertical concrete cask (VCC) for shielding and transferred to the ISFSI concrete storage pad.

All major fuel loading, packaging, and transfer activities were directed by trained and qualified Cask Operations Shift Supervisors. Throughout the fuel transfer strict use and adherence to procedural guidance was enforced. Work was frequently stopped to resolve questions, concerns, or to evaluate work progress. Detailed radiological control planning was evidenced by the integration of as-low-as-is-reasonably-achievable (ALARA) controls in procedures and work practices. The first pool-to-pad fuel transfer evolution was accomplished for a total radiation exposure of less than 200 mrem (2 mSv).

The original fuel transfer schedule had a total of ~ 18 months to offload the spent fuel pool. Overall fuel transfer project delays were threatening the total project schedule, so Maine Yankee purchased a second fuel transfer cask in order to work on more than one canister at a time. One canister could be loaded in the spent fuel pool while a second, filled fuel canister could be vacuum drying. The use of the second transfer cask was expected to reduce the fuel transfer effort to ~ 12 months.

Over the following five months, eleven canisters were transferred to the ISFSI pad. In January 2003, Maine Yankee terminated the existing contract with the cask provider as they were unable to perform under the existing contract. Maine Yankee took over fuel loading and transfer operations while options were evaluated for the project completion. In April 2003, a new contract with the cask provider was issued for the remaining dry cask hardware for the project. Maine Yankee continued to perform fuel management and transfer operations. Fuel transfer activities concluded in late February 2004. A total of 60 spent fuel canisters and four GTCC canisters were stored on the ISFSI pad. The average cask loading rate for the Maine Yankee team was just under eight calendar days per canister with those toward the end of the project being loaded and transferred in approximately five days.

The completed ISFSI pad and fuel canisters are seen in the following figure.

Figure 5-2 Maine Yankee ISFSI Pad and Dry Storage Casks

Additional Fuel Related Issues

Maine Yankee had fuel failure issues early in plant operation. This required that when the detailed fuel inspection and verification occurred that the plant have in place a contingency program to deal with any fuel fragments/pellets found. This contingency program needed to deal with both radiological and safeguards issues. This inspection and verification program was conducted prior to any fuel canister loading could be performed.

Of the total 1436 fuel assemblies that were transferred to the ISFSI, nearly 300 of them were considered "non-standard" fuel by virtue of actual or potential fuel failures. Specific reviews were essential with the dry cask system provider to assure the canister/cask system was correctly licensed for all the materials to be stored within, including GTCC and non-standard fuel.

Maine Yankee had a boronometer source which posed a special disposition challenge. This source was a plutonium-beryllium (Pu-Be) neutron source. Other facilities also have these sources or americium-beryllium (Am-Be) sources for boron concentration measurement or for other use as neutron sources. In the case of Maine Yankee, they received a legal opinion that the boronometer source was not "associated with the fuel". As such, it could not be disposed of in a

DCS canister. The source activity was such that it could also not be disposed of in available low-level waste burial sites. Maine Yankee then applied to the DOE orphan source program. Ultimately, this was successful, but the source disposal required four years of interaction with DOE to accomplish.

6 REGULATORY AND STAKEHOLDER INTERACTION

Lessons Learned/Recommendations

- In addition to addressing radiological decommissioning issues it is equally important to address non-radiological issues in decommissioning.
- Early in the project, Maine Yankee didn't fully appreciate the level of non-radiological stakeholder and regulator interaction that would be necessary to accomplish the decommissioning.
- It is essential to build trust with the various project regulators.
- Develop and get agreement on conditions for the site characterization before samples and measurements are taken.
- Include reduction in records retention requirements among the various regulatory exemption requests to be submitted.
- Negotiation is often better than litigation. Although the various negotiated settlements for Maine Yankee required additional tasks to be performed, Maine Yankee's assessment was that if litigation was the overall project selected approach, that the project completion would have been delayed up to two years.
- Get agreement on nuclide fraction (NF), dose pathways, and what to do when you find different NFs during characterization.
- Get regulators and stakeholders involved with the Data Quality Objective (DQO) process earlier in the decommissioning project. Set up a DQO organization with primary stakeholders – essentially when final shutdown occurs. Meet on a monthly basis similar to CAP, on the technical matters that are needed for the License Termination Plan.
- If you have an engineer who can discuss technical issues in a manner people can understand and can provide answers, it is a great asset toward moving community opinion.
- If you initiate a program similar to CAP, it is essential that top management accept, or buy into the program in order for the organization to give it the appropriate level of attention.

Introduction

It may be reasonable to expect that interactions with regulators are separate from those with stakeholders, however this was seldom the case for Maine Yankee. During its operating life, Maine Yankee was the object of three Maine state referendums that attempted to shut the plant down. In each case, Maine voters chose to keep the plant open, however this demonstrated the level of stakeholder interest in the facility.

Many key decommissioning project regulatory decisions were impacted by stakeholder input. This section provides a discussion of the Maine Yankee interaction with both regulators and stakeholders in the following project topics:

- Federal Energy Regulatory Commission (FERC) Rate Case;
- ISFSI Pad Permitting;
- Rubblization Decommissioning Approach; and,
- Site Release Criteria.

In order to address regulators and stakeholders, it is important to understand all the potential participants. Maine Yankee is regulated by both federal and state government agencies. These agencies and organizations include:

- U.S. NRC;
- U.S. EPA;
- U.S. FERC;
- Maine Department of Human Services (DHS), Division of Health Engineering;
- Maine Department of Environmental Protection (DEP);
- Maine Public Advocates Office;
- Maine Public Utilities Commission.
- Maine Nuclear Safety Advisor – A liaison to the Governor and the Maine legislature;
- Maine Advisory Commission on Radioactive Waste and Decommissioning; and,
- Maine Governor's Technical Advisory Panel – Provides independent evaluation of technical decommissioning issues and to advise the Governor accordingly.

In addition to these regulatory groups, Maine Yankee also had a number of groups who intervened in regulatory matters, the most notable of these being the Friends of the Coast – Opposing Nuclear Pollution (FOTC). This organization had been an active anti-nuclear group opposing Maine Yankee for a number of years during its operation.

One specific issue early on in the decommissioning project which required regulator interaction only was records retention and disposition. During plant operations, a wide range of records are required to be maintained onsite and accessible. Requirements for records retention are contained in 10CFR50, Appendix A, Criterion I which states:

> "Appropriate records of the design, fabrication, erection and testing of structures, systems and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit."

This is relatively clear for plant operation, but becomes far less so during decommissioning. As decommissioning continued, it became a greater burden to maintain all plant operational records

in a manner consistent with regulation. Maine Yankee became aware of a letter from the NRC Office of General Counsel (OGC) to the Trojan Nuclear Plant in March 2003 which stated the OGC opinion that all the records should be maintained until the NRC license was terminated.

On a practical matter, it didn't seem to be reasonable to be required to maintain all quality assurance required documentation on a reactor coolant system whose components resided at the Barnwell and Envirocare low level waste burial sites. Consequently, Maine Yankee submitted its own interpretation of the regulations to the NRC, asking that if the NRC disagreed with the Maine Yankee position, that the NRC consider their interpretation as a formal Exemption Request. OGC responded by reiterating the position stated in the Trojan letter that records were required to be maintained until license termination, and that the request would be processed as an Exemption Request.

In November of 2003, the NRC approved the Maine Yankee Exemption Request allowing for the disposal of a wide range of record no longer necessary based on the condition of the facility.

FERC Rate Case

When Maine Yankee shutdown in August 1997, its decommissioning trust fund was insufficient to pay for the decommissioning which was estimated to cost $380 million over seven years plus an additional $128 million for spent fuel storage and management. On November 5, 1997 Maine Yankee applied to the FERC to increase its annual decommissioning collections from ratepayers from $14.9 million to $36.4 million.

Various Maine agencies and an environmental organization, along with representatives from other states in New England, intervened in the FERC process. The Maine Public Utilities Commission, the Maine Office of Public Advocate, and FOTC were intervenors from Maine. By intervening, each group earned the right to participate in the FERC negotiations with Maine Yankee. Maine Yankee could have proceeded to FERC for a hearing, but instead chose to negotiate with the intervenors.

In mid-January 1999 a settlement agreement was reached. In June 1999 FERC approved the settlement agreement. The settlement stipulated the following:

- $33.6 million will be collected annually and allocated as follows:
    - $26.8 million for dismantlement activities
    - $6.8 million for construction and operation of the on-site storage facility for used fuel.

Additionally, the settlement agreement stipulated that Eaton Farm, including approximately 200 acres of Maine Yankee property, will be donated to a non-profit environmental organization or school for environmental education, a nature preserve and public access. A $200,000 grant will also be provided by Maine Yankee to the non-profit organization for the project.

The settlement required Maine Yankee to re-file a rate case by January 1, 2004 to recover the future costs of managing spent fuel left on site after decommissioning. The settlement also

resolved an investigation in the prudency of the Maine Yankee's pre-shutdown operation. Maine Yankee's shareholders' return on equity was reduced from 10.65% to 6.50%. In addition, any gain on the sale, lease or disposal of land would be flowed through to customers instead of shareholders. Maine Yankee agreed in the settlement to continue to pursue all legal claims it may have against the DOE regarding spent fuel.

Maine Yankee agreed to manage expenditures to a budget of $446.3 million (in 1998 dollars) through December 31, 2004, to pay for all decommissioning and ISFSI related costs. If Maine Yankee's expenditures are less than $436.3 million then Maine Yankee shareholders have an opportunity to earn incentives. If the expenditures are over $456 million Maine Yankee shareholders will be required to pay 10% of the net overage even if the overages are prudently incurred. Any imprudent expenses would not be recoverable.

In addition, Maine Yankee is subject to financial penalties if the radiation exposure for all of the decommissioning work exceeds the generic environmental impact statement total site dose or if the industrial safety performance (recordable incident rate) exceeds 2 per 200,000 hours worked during decommissioning.

In addition, Maine Yankee reached a separate agreement with FOTC in the rate case, which provides:

- That Maine Yankee will conduct a field survey of off site marine sediments;
- That Maine Yankee will provide FOTC with information regarding any water transport of heavy components;
- That Maine Yankee will split ground water samples with FOTC;
- That Maine Yankee will impose a restriction against future use of the site for nuclear power purposes; and,
- Maine Yankee also agreed to use its best efforts, in conjunction with the development of the ISFSI, to oppose any expansion of the ISFSI facility beyond that necessary for the storage of waste generated by Maine Yankee.

ISFSI Pad Permitting

The construction of the ISFSI pad required that Maine Yankee obtain various building permits. The first meetings with the Wiscasset Planning Board occurred in early March 1999. Maine Yankee was also required to submit a Site Development Application Amendment to the Maine Department of Environmental Protection. This was submitted in early May 1999. The application was transferred to the Maine Board of Environmental Protection (BEP) in August 1999. BEP assumed jurisdiction for the permit and issued notice of its receipt intending to conduct public hearings on the requirements for the ISFSI, including radiological requirements. Intervenor status was granted to Wiscasset and FOC.

In this case, Maine Yankee sought the litigation approach to determine if BEP had jurisdiction on the radiological aspects of the ISFSI. This action was taken in early September 1999. In January

2000, the case had not been resolved, and the lack of a construction permit was directly affecting the schedule for the project. In March 2000, two federal judges recused themselves from the case. In order to move forward, Maine Yankee asked BEP to immediately proceed with a hearing while the jurisdiction case proceeded. This hearing was scheduled for May 10, 2000.

On May 5, 2000 a federal court ruled that the state had no jurisdiction over radiological issues related to the project. This limited the BEP role to soil, wetlands and visual impact. The only BEP outcome at the hearing was for Maine Yankee to improve the visual screening for the ISFSI.

Maine Yankee received the requisite construction permits from the state and Wiscasset in July 2000. In September 2000, the ISFSI construction contract was issued and ISFSI pad construction was begun.

Rubblization Approach to Decommissioning

One aspect of the DOC contract was for the DOC to determine the specific decommissioning strategy within the general constraints provided by Maine Yankee in the contract. The decommissioning strategy selected by the DOC included removing all above ground concrete, remediating the concrete to appropriate radiological criteria, and using the concrete for fill material in below grade open structures. Maine Yankee pursued this approach with appropriate regulators and stakeholders.

The first public discussion of this rubblization concept was during the CAP meeting on September 17, 1999. The rubblization approach was discussed in the DOC prepared draft License Termination Plan (LTP). The DOC intended for the LTP to be submitted to the NRC in November. The CAP members had a number of questions and concerns with the approach and this CAP meeting and those that followed had “spirited” discussion of the rubblization approach. Many CAP members took the view that this approach was in essence onsite disposal of radioactive materials given that the concrete may have detectable levels of radioactivity although below the limits specified in the LTP.

In this case, Maine Yankee interviewees stated that they did not sufficiently prepare or educate the CAP members on the rubblization approach prior to the CAP members reading the draft LTP chapters.

In general, CAP members and the public were widely against the approach. Maine Yankee continued to pursue the option by including it in the Revision 0 LTP which was submitted to the NRC on January 13, 2000. This was a new issue for the NRC and prompted the staff to issue SECY-00-0041, Use of Rubblized Concrete Dismantlement to Address 10 CFR Part 20, Subpart E, Radiological Criteria for License Termination. In the purpose to the SECY it states that rubblization,

> "appears compatible with the radiological performance criteria for license termination. However, it was not specifically considered in the "Statement of Consideration" to the final rule, and is somewhat controversial.”

Various actions were taken by the state in an attempt to stop the rubbization approach. For example, the state (having large latitude in waste characterization) indicated that the rubblized concrete would not be considered Construction and Demolition Debris (CDD), that the concrete would be considered "special waste" with its own requirements for disposal as it was produced in "unusual quantities". This would increase the costs of the concrete disposal.

Additionally, the state could have taken action which would have required Maine Yankee to removal all sub-surface foundations, not just removal to three feet below grade. Maine Yankee estimated that if this were to become a requirement, it would increase the total decommissioning project cost by approximately $100 million.

In March 2000, state legislation was introduced which would require State of Maine monitoring of the Maine Yankee decommissioning. It also defined concrete as special waste and would impose a state limit of 0.05 mrem/y (0.5 μSv/y) for any residual radioactivity on site.

As an outcome of other stakeholder interactions, Maine Yankee had agreed to an enhanced cleanup level of 10 mrem/y (0.1 mSv/y) through all pathways and 4 mrem/y (40 μSv/y) through the groundwater pathway. This agreement was noted in the LTP submitted to the NRC in January 2000, and reflected in the ultimate state legislation passed in April 2000.

Although the state legislation would still have allowed rubblization under certain restricted conditions, based on the wide ranging stakeholder concern, the rubblization approach was abandoned. As noted by Maine Yankee personnel during interviews for this report, ultimately there was likely no significant difference between rubblizing and not. If the rubblization approach was pursued, it would require substantially more concrete surveying and remediation than by simply demolishing and shipping to an appropriate disposal site.

Site Release Criteria

The aspect of decommissioning which required the greatest interaction with regulators and stakeholders was not surprisingly the final criteria the site must meet to be "clean". Maine Yankee began the decommissioning project with the intent to conduct remediation sufficient to meet the NRC requirements of 25 mrem/y (0.25 mSv/y) through all pathways and the demonstration of ALARA requirements. No remediation was expected due to EPA requirements. The final criteria ultimately required were substantially more restrictive.

As noted above, the initial License Termination Plan (LTP) was submitted to the NRC in January 2000 and included the enhanced radiological cleanup criteria of 10 mrem/y for all pathways and 4 mrem/y for the groundwater pathway. This was the result of long interactions with stakeholders beginning in August 1997 when the FOTC asked that Maine Yankee meet the EPA proposed radiological release criteria of 15 mrem/y + 4 mrem/y groundwater.

Discussion at CAP meetings continued into 1998 on the differences in the NRC and EPA approaches to dose limits, discussion of dose pathway analysis, and other aspects. In an effort to help educate the CAP members on the technical aspects of surveys and dose modeling, training on the MARSSIM protocols was provided to interested CAP members. MARSSIM (Multi-

Agency Radiation Survey and Site Investigation Manual) is a document developed by the US EPA, US NRC, US DOD, and US DOE to provide detailed guidance for planning, implementing, and evaluating environmental and facility radiological survey conducted to demonstrate compliance with dose or risk based release regulation.

The primary issue addressed at the October 1999 CAP meeting was the LTP release criteria and EPA release requirements (non-radiological). At the following CAP meeting in December 1999, four separate State of Maine departments as well as FOTC stated that the LTP should require cleanup beyond the NRC requirements.

Despite Maine Yankee agreeing to the more restrictive, "enhanced" cleanup criteria, on April 26, 2000, the State of Maine Law LD 2688-SP1084 was signed into law. This law specified an unrestricted release criteria of 10 mrem/y through all pathways and 4 mrem/y through the groundwater pathway. It also specified that any remaining concrete rubble contain no greater than 5,000 dpm/100 cm^2 residual radioactive contamination.

In the summer of 2000, the State of Maine and FOTC petitioned the NRC to intervene on Maine Yankee's LTP. The NRC subsequently appointed an Atomic Safety and Licensing Board (ASLB) to consider the petitions and request for a hearing. Rather than pursue the ASLB hearing, Maine Yankee asked for and received an abeyance on the hearing in order to work with the State and FOTC to resolve their issues.

Over 30 stakeholder meetings were held through the fall of 2000 and the spring of 2001 which led to the development of revised LTP bases. Revision 1 of the LTP, which included major changes, was submitted to the NRC in June of 2001. An additional revision (revision 2) was submitted in August 2001 which included additional comments from the State and FOTC.

At the end of August 2001, a settlement agreement was reached with the State and FOTC and accepted by the ASLB eliminating the need for hearings. Key aspects of the settlement included the following:

1. Maine Yankee and State Of Maine

   - Maine Yankee and the State of Maine will work jointly with the NRC to determine whether the intertidal zone is within or beyond the site boundary, hence within or outside the scope of 10 CFR 50.82.

   - Maine Yankee and the State of Maine will jointly participate in a process to resolve the outstanding technical issues in the LTP. This Technical Issues Resolution Process (TIRP) would use the Data Quality Objective process outlined in MARSSIM.

   - In a subsequent LTP revision, Maine Yankee would clarify the relationship between the free release criteria in the LTP and NRC Circular 81-07.

   - Maine Yankee will notify the State prior to making changes to the LTP in accordance with 10 CFR 50.59 that would result in any increase in the Derived Concentration

Guideline Levels (DCGLs) and to request NRC approval if the DCGL increased by a factor of two or greater.

- Maine Yankee agrees to obtain additional radiochemical analysis of groundwater from the containment sump.
- Maine Yankee will use the radiological results obtained in implementing the LTP as well as the output from the RCRA health risk assessment (see section X) and compile a Cumulative Risk Assessment.
- Maine Yankee will have additional biota and marine samples taken and analyzed. The sampling program will be developed jointly with FOTC.
- Maine Yankee will provide the State with a listing of all parameters used in the LTP and their basis and include it in a subsequent revision to the LTP.

2. Maine Yankee and Friends of the Coast

- Maine Yankee will take and analyze additional samples in and around the forebay and diffuser discharge piping and incorporate the results and evaluations into a subsequent revision of the LTP
- Additional soil and vegetation samples will be taken and analyzed in areas of elevated soil contamination. The locations of the samples to be agreed to by FOTC.
- In general, Maine Yankee commits to using offsite areas as the background reference area if needed for implementing the LTP.
- Maine Yankee agrees to print ads in local newspapers asking former Maine Yankee employees and contractors to recount knowledge of any spills, incidents or other actions dealing with radioactive materials which should be included in the Maine Yankee Historical Site Assessment.
- Maine Yankee agrees to make flowrate measurements at a discharge point into Bailey Cove and to have samples taken of the outfall.
- FOTC shall receive information obtained from the groundwater and marine sampling performed as part of the agreement with the State.

It was noted in the November/December 2001 issue of Radwaste Solutions that

> "The agreement appears to be the first in the United States to include state officials and environmental activists in setting terms for license termination of a commercial nuclear power plant. It also appears to be the first to set cleanup standards that are more stringent than federal requirements."

Substantial additional detail on the Maine Yankee LTP and Historical Site Assessment can be found in EPRI Report # 1003426, Summary of Utility License Termination Documents and Lessons Learned: Summary of License Termination Plans Submitted by Three Nuclear Power Plants, and EPRI Report # 1009410, Capturing Historical Knowledge for Decommissioning of Nuclear Power Plants: Summary of Historical Site Assessments at Eight Decommissioning Plants.

Community Advisory Panel (CAP)

The Maine Yankee Community Advisory Panel (CAP) was established in 1997 to enhance opportunities for public involvement in the decommissioning process of Maine Yankee. The CAP represents the local community. By thoroughly reviewing the decommissioning process, the CAP is in a position to advise Maine Yankee on key issues of concern to the local community.

One of the first actions in development of the CAP was the creation of the Charter. This document provided the overall structure of the CAP, its operating approach and the operating envelope – what was in their purview and what was outside.

During its first year, the CAP received several technical tutorials on subjects such as radiation, the decommissioning process, decommissioning funding, site characterization, trash monitoring, emergency planning, and spent fuel storage. CAP members also visited used nuclear fuel storage sites at nuclear plants in Maryland, Colorado and Michigan. These visits gave CAP members first hand information about how dry storage facilities work.

After its first year of intense learning, the CAP met in September 1998 to revisit their role and establish a work plan for 1999. Since that time, the CAP annually established a work plan each September for the following year. This annual planning session also provided the CAP to evaluate the work plan against their own deliverables to judge and self critique themselves.

The CAP also shares information with other advisory panels. For example, the Maine Yankee CAP has met with citizen panels at Connecticut Yankee, Big Rock Point, and Millstone. CAP members have also participated in national and international conferences regarding decommissioning and have toured the proposed DOE spent fuel repository at Yucca Mountain, Nevada.

The CAP provided an effective vehicle to obtain community and stakeholder input and to provide to Maine Yankee a means to communicate a consistent message to a diverse group. Two early instances in which the CAP provided a particularly effective means of communication included spent fuel pool fan noise and the Wiscasset landfill. The noise from the SFPI cooling fans was addressed earlier.

The incident at the Wiscasset landfill arose when a concern was raised in a CAP meeting that in the 1980's, Maine Yankee had allegedly sent potentially contaminated material to a local landfill. A detailed investigation was conducted by Maine Yankee along with NRC and state regulators. The investigation determined that during a portion of 1986 and 1987, that Maine

Yankee had sent materials which were radiologically released from a “bag monitor” to the landfill. For various reasons the use of the bag monitor was discontinued by Maine Yankee in 1987. The investigation also included water sampling and land surveys at the now closed landfill site. Similar surveys and sampling were also performed by the NRC and state agencies. The survey and sampling results showed only background levels of radiation and contamination. The investigation progress, as well as results were conveyed in subsequent CAP meetings, including discussion of the health impacts from an independent nationally known health physicist. The prompt action by Maine Yankee as well as the transparency in which the investigation was conducted worked to Maine Yankee’s favor by building trust with the regulators and stakeholders.

One thing that was essential to the CAP members was that they wanted real issues to address and to provide input on, and that Maine Yankee would view their input with weight. It became evident to the local media that these meetings would be newsworthy, so at least for the first year, media coverage of the meetings was typical. Maine Yankee staff worked very hard to keep the CAP from being surprised by anything relating to the project in the media – the CAP expected to hear it from Maine Yankee first.

A key value to CAP, and to the company and to the community was that on a very regular basis, senior plant management made presentations before the public and were expected to answer the questions in a manner understandable to lay members of the public. This was a challenge for some site personnel to be able to communicate in this manner. The CAP also served by making MY carefully prepare for presentations and to help ensure a clear, consistent and understandable message got to the public, for examples with the LTP, fuel storage, and explosive demolition.

Maine Yankee did not provide training to personnel prior to presenting material at CAP. Some people took to the task readily, and others improved with experience. Public Affairs Department personnel would help people prepare material and would do dry runs on the material before CAP, including probable public questions. Over time, CAP built up trust with regular presenters. Also, before each CAP meeting Maine Yankee would provide dinner and the site presenters would participate. This social interaction also helped build a rapport between the CAP members and the presenters.

The attendance at CAP meetings was never terribly high (20-30) and periodically, CAP would question the low attendance. The only item really noted was that since media was there, the public could follow the issues in the local newspapers. The only times when public participation was high was when there were issues that directly affected them (SFPI fan noise being the biggest item).

Explosive demolition is another good example of when the CAP was of value. The first time explosive demolition was discussed internally to Maine Yankee, it seemed an unlikely prospect for success from the stakeholder viewpoint. Once it appeared to be sound from a technical and economic standpoint it was presented to CAP. Detailed discussion and questions occurred over a number of CAP meetings, so that when the explosive demolition occurred, it was well understood and of little public concern. The same detailed discussions, planning and communication was used successfully for all the explosive demolition applications.

If a company is considering a CAP or its equivalent, it must understand and accept the level of effort needed to keep it going. When the Maine Yankee CAP was started, the "care and feeding of CAP" was essentially a full time position for one person. A substantial effort was made in the first two years in order to build the trust and credibility needed for success. In addition to the staff support, Maine Yankee budgeted for the travel and education opportunities provided to the CAP members as well as the dinners provided prior to each CAP meeting. Nominally, this was approximately $20,000 per year, but was viewed by Maine Yankee as providing real value for the funds and effort expended.

Perhaps a single comment from one of the interviewees summarizes the view of Maine Yankee toward the CAP.

> "I am absolutely convinced that the CAP was one of the real keys why the decommissioning was successful, because it was an opportunity for a diverse group from the community, who had some really spirited discussions among themselves to come together in understanding complex issues for the benefit of the community and to Maine Yankee"

7 ENGINEERING AND USE OF TECHNOLOGY

Lessons Learned/Recommendations

- Segmentation – For internals segmentation, assure the RFPs address detailed controls and limits for air and water contamination.
- Segmentation – Continuous monitoring of waste debris accumulating in the high integrity containers requires multiple survey points to ensure shipping dose rates of the casks are not being exceeded. Additional remote monitoring detectors were installed on the high integrity container liners during the project.
- Segmentation – The use of a remotely operated capping tool to install lids on the high integrity container liners would help reduce radiation exposure.
- Segmentation – Design improvements are needed to enhance the vacuuming and debris removal operational efficiency.
- Segmentation – Modular and quick disconnect features are needed for all submerged systems
- Segmentation – A complete flush and verification of the primary loop cleanliness after the loop decontamination was needed.
- Explosive Demolition – Explosives are a viable alternative to mechanical demolition. For Maine Yankee, explosives were used as it was estimated to reduce the demolition time by a factor of 3 – 5. You must however balance the improved production rate against the increased costs for explosives use.
- Explosive Demolition – It is essential to maintain strict security oversight of the transfer and accounting of all explosives onsite.
- Explosive Demolition – It is prudent to include an explosives handler in the initial post-blast inspection entry team.
- Explosive Demolition - When the containment concrete interior was removed, it cut out about 99% of the remaining activity – this allowed much less risk with the use of explosives.

Overview

The decommissioning of Maine Yankee involved a wide range of engineering skills and use of technology to optimize the overall project results. Two technology applications are briefly addressed here. The first being the project to segment the reactor vessel internals and the second being the use of explosives for building demolition work including the turbine building, containment polar crane, and containment shell.

Reactor Vessel Internals Segmentation

The segmentation of the reactor vessel internals was performed by abrasive water jet and mechanical cutting by Framatome ANP. No thermal cutting techniques were used. The initial cutting activities began in November 2000. The initial estimate of weight was 363,000 pounds with 70% shipped with the reactor vessel, 20% shipped in casks and 10% (GTCC) stored in the ISFSI. The activity was estimated at 1.964 million Curies (7.267E16 Bq) of which 2% was shipped with the reactor vessel, 15% shipped in casks and 83% (GTCC) stored with the ISFSI. The entire project was estimated to require 57 person-rem (0.57 person-Sv) to complete. The project ultimately required only 29 person-rem (0.29 person-Sv) to complete.

Full "proof testing" was performed for the segmentation system at Framatome. This activity took longer than anticipated and ultimately resulted in the project starting on site about eight months late. The planned total onsite work duration was correct, so the result was the project ended about eight months later than planned.

Maine Yankee used lessons from Rowe, and kept a consistent focus on maintaining water clarity. The segmentation approach was to cut the internals into larger sections which didn't have to put into individual fuel cask cells. A special cask container was fabricated for fragments and larger pieces. This substantially reduced the number of required cuts, hence reduced debris and swarf. A detailed CAD/CAM based plan was developed to plan cuts, detailed tool movements, and placement of pieces into cask. This allowed for optimization of cask loading and required the fewest cuts and piece movements. Cut away views of the reactor pressure vessel and internals prior to any segmentation is shown in Figure 7-1. The planned cuts on the thermal shield and core support barrel are shown in Figure 7-2. A view of the partially segmented internals is provided in Figure 7-3.

The reactor pressure vessel (RPV) internals segmentation was performed in the flooded refueling cavity. Cavity penetrations were sealed to confine the cutting debris to the reactor cavity. Reactor cavity housekeeping and contamination controls were strictly maintained to prevent buildup of high radiation sources. In order to minimize cross contamination, the cutting was performed first on the least activated components and progressed to cutting the most highly activated materials.

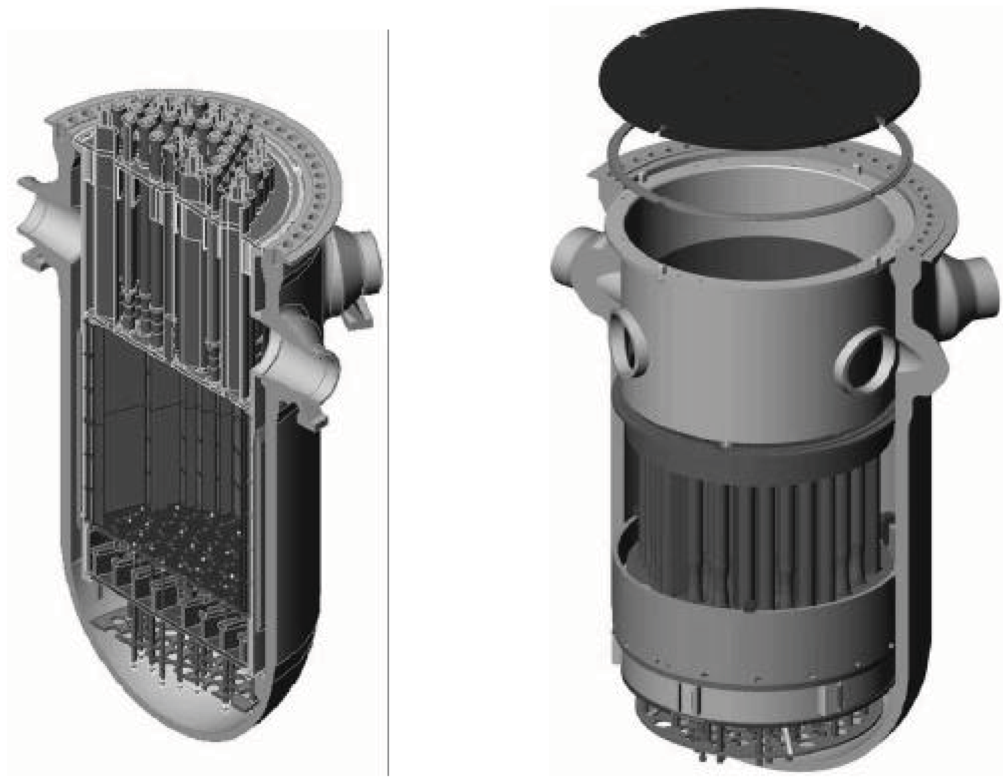


Figure 7-1 Maine Yankee RPV and Internals Prior to Segmentation

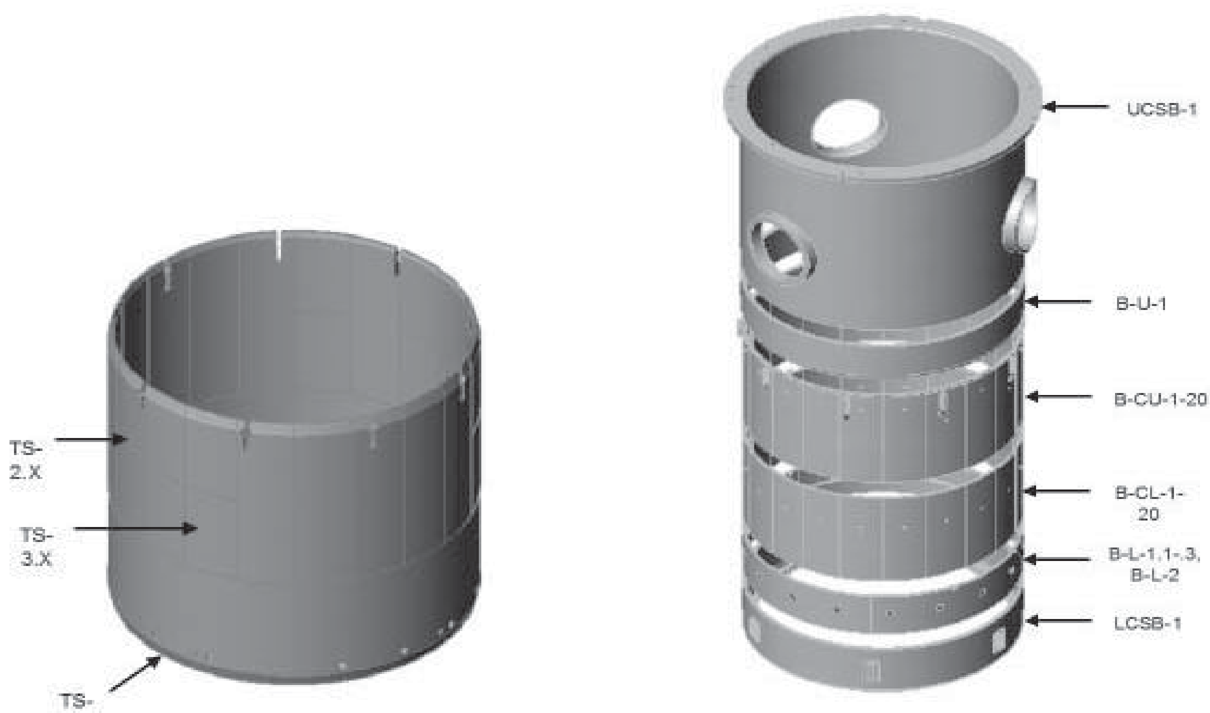


Figure 7-2 Maine Yankee Projected Cuts on Thermal Shield and Core Support Barrel

Figure 7-3 Maine Yankee Vessel Internals Segmentation

The water jet cutting was performed with a four axis telerobotic manipulator that was remotely operated. Custom designed and fabricated rigging equipment was used to assist in the lifting and positioning of the internals. A number of other innovations were developed during the segmentation process, including vision enhancement during cutting, capture of cutting waste and a new licensed waste container for the high level abrasive swarf. Maine Yankee in particular found the control and precision of the telerobotic manipulator (the "mast") to be quite good. It allowed for very precise x/y/z location control for cuts. The ultimate results were only four casks of GTCC were generated. Approximately 2/3 of the cut internals were able to be put back into the reactor pressure vessel for subsequent disposal using the custom rigging equipment as shown in Figure 7-4.

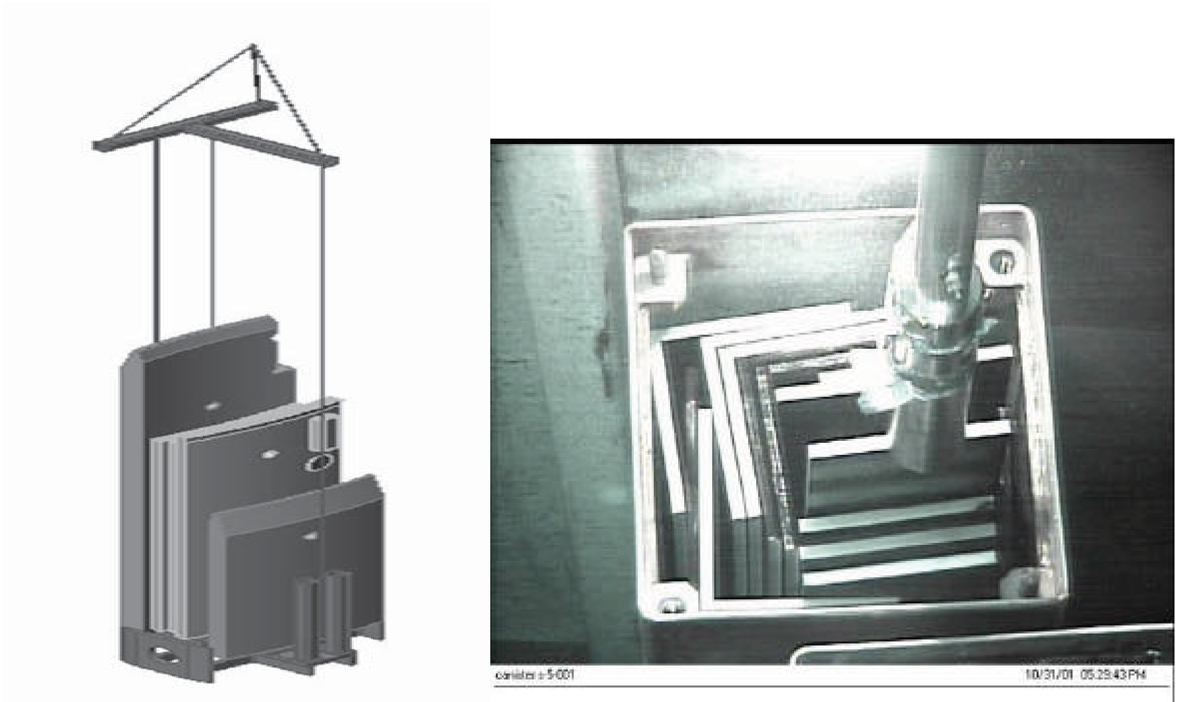


Figure 7-4 Maine Yankee Lifting Rig with Segmented Pieces and Placement Back Into Vessel

The most difficult challenge in the internals segmentation process was the removal of the colloidal suspension created from the fragmentation of the garnet used in the abrasive water jet cutting. Initial testing demonstrated that a simple filtration system quickly clogged. A specially designed and patented filtration system was fabricated for the actual water jet cutting operations. This Solid Waste Collection System (SWCS) was used with a separate Cavity Water Treatment System (CWTS) in order to control debris cleanup and water clarity. Another challenge was an initial crud burst from the residual reactor coolant system decontamination wastes due to incomplete flushing of the system after decontamination.

Maine Yankee used larger than fuel assembly sized containers for their GTCC waste in order to reduce the number of segmentation cuts that were required. These waste containers held two canisters approximately 6 feet in diameter and 8 feet tall. Two canisters containing GTCC waste were stacked on top of each other in one waste container. A total of four waste containers with GTCC wastes and 60 containers with spent fuel were moved into dry cask storage and placed on the ISFSI storage pad. The reactor pressure vessel containing the lower activity internals segments was removed from the containment in August 2002 and prepared for shipment via barge to the Barnwell disposal site. Due to low water levels in the Savannah River, the reactor pressure vessel did not leave Maine Yankee until May 2003 (Figure 7-5).

Figure 7-5 Maine Yankee RPV Ready for Transport to Barnwell

The Maine Yankee reactor vessel internals segmentation along with the segmentation of other reactor vessel internals is discussed in detail in EPRI Report # 1003029, Decommissioning: Reactor Pressure Vessel Segmentation. A portion of the material above was obtained from this EPRI report.

Use of Explosives

As noted in this and earlier sections, Maine Yankee encountered some project delays due to the overall effort to remove all fuel from the spent fuel pool and the fuel building. This action was required to be complete prior to final fuel building demolition. One way in which Maine Yankee worked to recover some of the project schedule was the use of controlled explosives for a portion of the building demolition. In particular, for building demolition efforts in which the standard mechanical demolition equipment (e.g., ram hoe) could not reach high enough from ground level to affect the upper elevations/roof of plant structures.

When the use of explosives was initially evaluated, the following design requirements were established.

- Damage to nearby structures, systems and components including those involving safe storage of spent fuel must be avoided. These potentially affected structures, systems and components included the Fuel Handling Building, Spent Fuel Pool Transfer Tube, Spent Fuel Storage Racks and Spent Fuel Assemblies. Other non-safety related structures, systems and components which could be affected include building ventilation and relays in the 345 kV switchyard which were sensitive to vibration;
- Offsite dose limits for gaseous effluents (including particulates) must be met;
- All applicable rules and regulations for use of explosives must be met;
- The analysis must demonstrate that the task can be performed safely;
- Overpressure due to the explosion in the vicinity of the ISFSI must not exceed the design value of 22 pounds per square inch, otherwise existing design criteria such as wind loading pressures and peak particle velocity, as well as ground motion were used to assess the consequences on the ISFSI for the use of explosives;
- Peak ground velocity limits for the spent fuel in the ISFSI was established at 1 inch/sec; and,
- The town of Wiscasset ordinance governing the use of explosives deferred to state law. Although not required, the state fire marshall's office was notified of the activity.

In addition to safety analyses required per 10 CFR 50.59, additional radiological analyses were performed. The analysis indicated that no significant exposure to the public would result from the demolition of buildings with low levels of contamination. As long as the average beta/gamma contamination levels are below 5,000 dpm /100 cm^2 (~ 83 Bq /100 cm^2) for loose surface contamination and 500,000 dpm/100 cm^2 (~ 8,300 Bq /100 cm^2) fixed contamination, the critical organ dose to any member of the public using methods in the Maine Yankee Offsite Dose Calculation Manual would be under 0.066 mrem (0.66 µSv) for the entire project. Alpha contamination limits of 20 dpm/100 cm^2 (~ 0.33 Bq /100 cm^2) for loose surface contamination and 100 dpm/100 cm^2 (~ 1.68 Bq /100 cm^2) fixed contamination results in a critical organ dose of 8.6E-3 mrem (8.6 nSv) for the entire demolition project.

In order to validate the calculations and models, Maine Yankee and their explosive demolition contractor performed low yield explosive tests in containment and the spray buildings. Following the initial blast in the sontainment building, walkdowns were performed to assess the impact (if any) on plant structures, systems and components. Maine Yankee reported that no damage was observed to the fuel, fuel pool, fuel pool cooling equipment, or structural walls. In addition, no leakage was detected at the spent fuel pool leakage detection system and no change in the fuel pool water level was observed. In addition no significant airborne radioactivity was generated during the blasting.

Following the blasting in the spray building on April 25, 2003, a Safety Representative and Health Physics technician discovered that several charges failed to detonate in the spray building. One of Maine Yankee's corrective actions was to ensure that during any future blasting, an explosives handler would be included in the initial post-blast inspection entry team.

Turbine Building Demolition

The turbine building was approximately 135 feet x 335 feet x 110 feet high, approximately 45,000 square feet and contained approximately 5.4 million cubic feet of free volume. Prior actions included removal of major commodities, galbestos siding and other possible contaminants. The structure had satisfactorily completed the final status survey and was ready for demolition. Controlled explosives were selected as the preferred method to soften the turbine pedestal before standard mechanical demolition, and to implode the turbine building roof trusses onto the building upper floors.

The turbine building pedestal provided support for the turbine-generator set and weighed approximately twenty-million pounds. The debris from the pedestal was expected to fill approximately 100 gondola rail cars, which would subsequently be shipped offsite over a ten week period.

The remainder of the building was demolished by a combination of standard mechanical means and explosive demolition. The southern eight bays (approximately 240 feet of length) were explosively dropped by the use of shaped charges which were strategically placed on the building's supporting frame. The northern section of the building was mechanically dismantled later due to its proximity to equipment important to safety. The use of controlled explosives was determined to be a safer approach for workers as it reduces worker time in the building and reduces worker exposure to dust. Overall the process produces less noise and dust as the total time to complete demolition was reduced from approximately two months using standard equipment to approximately two weeks.

A substantial safety analysis was performed to use the controlled explosives approach. In particular, the impacts had to be evaluated for the public (~ 0.5 miles from the blast point), workers, spent fuel pool (260 feet from the blast point), reactor cavity (200 feet from the blast point), 345 kV switchyard (660 feet from the blast point), ISFSI (1000 feet from the blast point) and control room (77 feet from the blast point).

Maine Yankee worked with the construction demolition contractor and the explosives company to design the blasts so that ground vibration would be limited to 50% of that allowed under the site design basis (1 inch/second).

In order to accomplish the demolition, vertical holes approximately 39 feet deep were drilled into the turbine building pedestal at three to four foot spacings for the explosives to be placed into (Figure 7-6). The roof trusses were severed with explosives which dropped the roof onto the turbine deck. The roof was 65 feet above the turbine deck and 100 feet above the ground. Dropping the roof allowed standard ground based mechanical demolition to occur (Figure 7-7)

Figure 7-6 Maine Yankee Turbine Pedistal - Explosives Placement and After Detonation

Figure 7-7 Turbine Building Demolition After Use of Explosives

Polar Crane Demolition

Maine Yankee's containment interior demolition project involved the use of explosives to bring down their 330-ton polar crane from the upper levels of the containment building. Special precautions had to be taken to ensure the detonation and subsequent dropping of the polar crane did not affect the integrity of the fuel pool and associated equipment, that ground vibrations would not affect other plant structures and the Central Maine Power Co. 345 kV Switch Yard, that explosives were properly controlled and transferred while on-site, and proper precautions were taken to control and monitor potential offsite releases of contaminated dust.

In preparation for the crane drop, Maine Yankee:

- Positioned concrete rubble and sacrificial concrete inside containment to reduce ground vibrations;
- Installed seismic monitors or geophones to monitor ground vibrations inside containment, at the ISFSI slab, at the 345 kV Switch Yard, in the Control Room, and at Westport Island;
- Installed three air blast curtains made of chain link fencing and fibrous fabric at the former equipment hatch access to reduce potential effluents;
- Wetted down concrete surfaces inside of containment for dust suppression;
- Removed or de-energized electrical components and fixtures in containment;
- Installed multiple air monitors inside containment, in the former equipment hatch, and outside of containment to monitor potential effluents;
- Maintained strict security oversight of the transfer and accounting of all explosives;
- Modified the fuel transfer tube to prevent damage during containment demolition by removing the portion on the tube extending into the refueling cavity and welded steel plates to cover and seal the fuel transfer tube;
- Conducted multiple plant briefings to effectively coordinate the work and ensure personnel safety; and,
- Conducted communications with the public and stake holders via press releases and telephone contacts.

Typical guidelines established by construction insurers for use of explosives specify a maximum ground velocity of 2 inches per second. For conservatism, Maine Yankee's engineering plans were intended to limit the peak ground velocity limit to 1 inch per second. The maximum measured ground movement as measured by a seismic monitor on the 20 foot elevation of containment was 0.1 inches per second.

On December 19, 2002, Maine Yankee safely brought down their 330-ton containment building polar crane. Maine Yankee's explosives contractor used approximately 37 pounds of shaped explosive charges (RDX) to cut the polar crane into three separate pieces, allowing it to fall approximately 50 feet onto concrete rubble and sacrificial concrete (Figure 7-8). No damage to the fuel, fuel pool, fuel pool cooling equipment, or structural walls was observed. In addition, no

leakage was detected by the spent fuel pool leakage detection system and no change in the fuel pool water level was observed. A follow-up inspection inside containment showed that the polar crane dropped onto the concrete rubble bed and sacrificial concrete as planned. Most horizontal surfaces were covered with about a 1/16 inch layer of concrete dust. Some damage, which was not unexpected, occurred to lighting and conduit as a result of the blast.

The air blast also damaged temporary wooden doors used at the containment access and the outer containment blast curtain located at the former equipment hatch was blown down. The crane drop also spread concrete dust and low level contamination (i.e., 1,000 dpm/100 cm^2 beta-gamma) into major hallways in the 20 foot elevation of the primary auxiliary building (PAB). Initial air sampling results performed inside the PAB, at the former equipment hatch, and outside the equipment hatch were all less than 0.3 DAC.

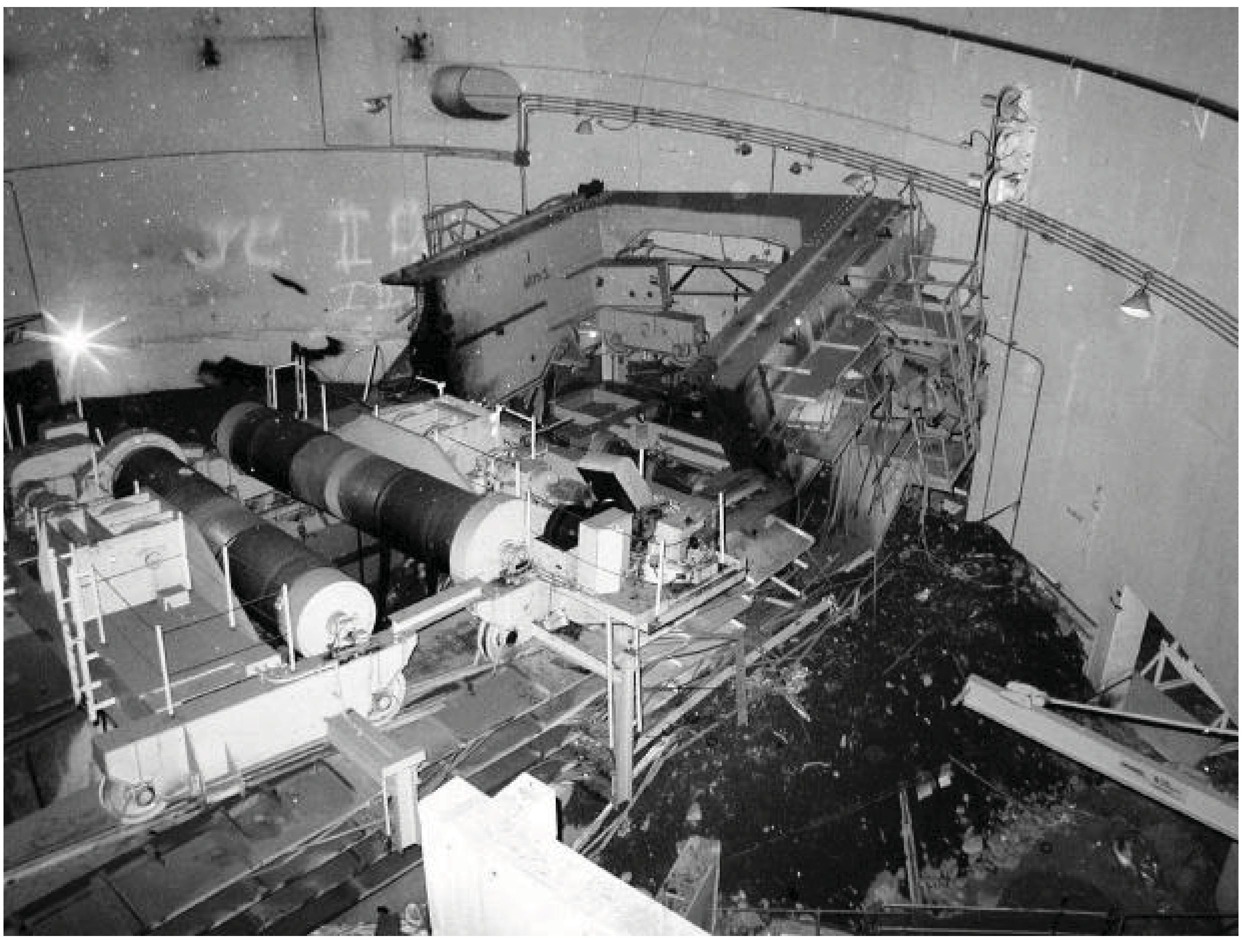


Figure 7-8 Maine Yankee Polar Crane After Explosive Segmentation

Containment Demolition

The containment was a 150 feet high cylinder 144 feet in diameter with 4 feet 6 inch walls at the base and a dome 2 feet 6 inches thick. It contained a steel liner between 3/8 and ½ inch thick. Similar to the turbine building demolition, the focus was on safety for workers, public and

nearby structures (primarily the spent fuel pool). Project planning began in January 2002 with demolition complete in September 2004.

Due to the robust nature of the 150 foot tall concrete and steel reinforced containment building, it was necessary to weaken it substantially before final demolition was possible. Nine 75-foot tall rectangular openings were cut through the exterior shell and steel liner using hoe rams and cutting torches. This resulted in the removal of two-thirds of the shell concrete and steel or about thirteen-million pounds of material. Additionally, all of the 2.25 inch diameter vertical reinforcing bars – approximately 1,360 of them – were cut (Figures 7-9 and 7-10). The columns were then drilled laterally for the 1,100 pounds of explosives used for final demolition. Prior to demolition the columns were wrapped in chain link fence and fabric to minimize flying debris.

Analysis identified that even with the large rectangular openings, the containment would still be capable of resisting wind loads up to 40 miles per hour. Administrative controls were then implemented to prohibit personnel access in and around the structure if wind speeds exceeded 40 mph.

Blast loads considered included the explosive demolition of the arches and the development of a high pressure air pocket under the containment dome as it collapsed after the arch demolition. The demolition sequence was therefore designed to progress circumferentially to allow the dome to tilt and land on edge. The dome and remaining portion of the containment were estimated to weigh 10,450 tons.

On September 17, 2004 the containment building was safely demolished with explosives, making it the first former nuclear power plant containment building to be demolished in this manner. This demolition resulted in approximately twenty-million pounds of rubble.

Figure 7-9 Maine Yankee Containment Demolition Preparation

Figure 7-10 Maine Yankee Containment Ready for Demolition

8 SITE CLOSURE ISSUES

Lessons Learned/Recommendations

- Site Release – For the overall project schedule, think about final status survey (FSS) as being the end point and structure the decommissioning work to support this end point.
- Site Release – Nuclide Fractions which exist per compliance with 10 CFR 61 are not necessarily nuclide fractions used for final status surveys
- Site Release – Maine Yankee developed a joint operational radiation protection/final status survey group. Maine Yankee had a core group of FSS technicians, but many technicians were cross trained. This added flexibility for work scheduling and task loading.
- Site Release - Much time was spent on decontaminating concrete rather than simply removal and disposal as waste ("rip and ship"). The project took too much time chasing cracks. It was decided for the containment interior to just have wholesale removal of concrete. This led to shipping approximately nine-million pounds of concrete, but allowed far less characterization and iterative decontamination. This also made FSS easier to perform.
- Site Release – The RCRA and state compliance was a bigger issue than anticipated. Some RCRA work will continue after NRC license termination.
- Site Release – Improvement in soil segregation and monitoring would be useful.
- Site Release – Maine Yankee didn't have ideas on soil remediation approaches early enough.
- Site Release – Do more quality control work on FSS data coming in from the field. Maine Yankee had many transcription errors.
- Site Release – Put a standard database in place early – it helps keep data consistent (e.g, 16 cm^2 vs. 15.5cm^2 probe area, types as simple example). Maine Yankee uses spreadsheet for data analysis.
- Site Release – Work with early characterization so that their data would better support FSS in addition to DOC required characterization.
- Site Release – Maine Yankee tried to have joint sampling for FSS/RCRA requirements but couldn't really accomplish this due to regulatory requirement differences.
- Site Release – Make sure you put all instruments through their paces before field use (e.g., temperature ranges, geometries, efficiencies, physical use parameters) – know all of these before you begin FSS measurements.

License Termination Plan Issues

The Maine Yankee License Termination Plan evaluated the potential doses for the following materials.

- Contaminated basement surfaces;
- Embedded piping;
- Activated concrete/rebar;
- Groundwater;
- Surface water;
- Surface soil;
- Buried piping/conduit;
- Deep soils; and,
- Forebay sediment.

The dose from each material was evaluated and summed to determine the total dose to the average member of the critical group. After considering radionuclide transfer from these nine contaminated materials, five environmental media were determined to potentially deliver dose to the resident farmer. These are groundwater, surface soil, deep soil, surface water and basement fill. The forebay sediment does not readily transfer to the five environmental media and was evaluated separately. The resident farmer was selected as the critical group for dose assessments. The dose assessment basis for each media is addressed below.

Dose Assessment Models - Concrete

All contamination on concrete surfaces is assumed to be released and mixed with the water that has infiltrated the basements. Contamination is assumed to be within top 0.1 cm of concrete. The highest concentration is obtained with the highest surface area to volume ratio. The highest ratio was found to be 1.7 m^2/m^3 in the spray building basement. This ratio was therefore used to determine volumetric contamination for all contaminated basement structures. Maine Yankee analysis showed an average concrete density of 2.2 g/cm^3

Contaminated basement surfaces result in exposures via the drinking water, irrigation, and direct exposure pathways. The drinking water dose is obtained by multiplying the basement water concentration (pCi/l) times the annual water intake (478 l/y per NRC guidance) times the applicable dose conversion factor from the Federal Guidance Report No. 11 (FGR-11 – Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion and Ingestion, Ref. 21). The irrigation dose was obtained by multiplying the basement water concentration (pCi/l) times the irrigation rate (0.274 $l/m^2/d$) over the affected area resulting in the applicable soil concentration. The soil concentration (pCi/g) is then converted to a dose using the NUREG 1727, Table C2.2 values. The direct dose was obtained using a standard industry shielding code assuming a three-foot cover, 10,000 m^2

affected area and a 5.8 m depth (representing the deepest basement). The resultant exposure rate is multiplied by the outdoor occupancy factor of 0.1101 from DandD version 1.0 (an NRC approved dose pathway analysis computer code used in decommissioning).

Activated concrete and rebar were also evaluated for basement concrete. Each showed a different nuclide mixture and characterization showed that the rebar contained approximately 1.9 times higher total activity concentration than did the concrete surrounding the rebar. Calculated doses however showed that the total contribution from the rebar was less than half that from the concrete. The decision was therefore made to assume that the entire volume was composed of the concrete and ignore the rebar contribution – providing for a conservative dose calculation.

The approach used for embedded piping was similar to that used in contaminated basement concrete. A determination was made of the potential radionuclide inventory in any remaining embedded piping, and the calculation assumes this entire inventory was released into the worst-case basement volume.

The calculations for surface soil use the NRC screening values from NUREG 1727, Table C2.3. A separate calculation is developed for deep soil, as the screening values only apply to the top 15 cm of soil. The resident farmer is exposed from deep soil through the direct exposure pathway and groundwater. As any excavation could move deep soil to the surface, the deep soil Derived Concentration Guideline Level (DCGL) was limited to no exceed the surface soil DCGL. The direct exposure contribution assumed a 15 cm cover (surface soil) and a volumetric source of 48,500 m^3. This value represents essentially the entire volume of soil within the restricted area down to bedrock. The direct exposure contribution was developed with an industry shielding code using default DandD values for indoor occupancy (0.6571y), outdoor occupancy (0.1101 y) and external radiation shielding factor (0.5512).

The maximum groundwater contributions were calculated using RESRAD (a DOE developed dose pathway analysis computer code) based on unit concentrations of each nuclide.

Dose Assessment Models - Groundwater

A separate calculation was developed for existing groundwater. Potential additional groundwater contributions from other contaminated materials are included in the applicable dose calculation. The groundwater dose was calculated from the highest individual groundwater sample result from site monitoring wells. The only nuclide identified in site groundwater is H-3 with a maximum concentration of 6812 pCi/l. The dose was calculated using the 478 l/y intake and the FGR-11 dose conversion factors.

Dose Assessment Models – Surface Water

The only sources of site surface water are the fire pond and the reflecting pond. No plant derived nuclides were identified in the fire pond, so only the reflecting pond was evaluated in the dose assessment. H-3 was identified in the reflecting pond at a maximum value of 960 pCi/l. Although this likely is a background level, the doses were likewise calculated for this input. In

addition to direct water intake, a potential pathway is fish ingestion. The dose was calculated by combining the water intake result (obtained as in the groundwater calculation above), and using the DandD fish consumption rate and a water to fish contamination transfer rate of 1.

Dose Assessment Models – Piping and Conduit

This calculation evaluates remaining subsurface piping and conduit – not embedded in concrete. This material is expected to contain little or no residual contamination. The piping is assumed to be evenly contaminated and that the entire inventory enters a soil volume equal to the internal volume of the pipe that assumes that the entire pipe has disintegrated. The resulting contaminated soil produces a potential dose that is calculated as in the deep soil approach discussed above, except that a three foot cover is assumed rather than 15 cm. The resultant DCGLs will be limited to not exceed the surface soil DCGLs.

Dose Assessment Models – Forebay Sediment

Initial characterization noted positive results for Co-60 from 0.04 – 11.2 pCi/g and for Cs-137 from less than the minimum detectable activity to 0.53 pCi/g. The minimal sediment that exists is found between rocks on the canal dikes and at low tide. The small sediment volume is reasonable considering the high water flow through the canal during plant operations. Additional characterization noted the following:

- Co-60 – 31.7 pCi/g;
- Fe-55 – 13.6 pCi/g;
- Ni-63 – 8.9 pCi/g;
- Cs-137 – 1.2 pCi/g; and,
- Sb-125 – 0.4 pCi/g.

The dose assessment assumes an inch layer of sediment at the base of 2 foot diameter rocks with an individual standing on or walking over the rocks. The pathways to consider are direct exposure and ingestion. Inhalation was deemed not reasonable as the sediment is either submerged or wet at all times. Resultant doses were approximately 8 times lower than the soil exposure contributions.

Containment Concrete Issue

Characterization and remediation in the lower levels of the containment indicated that there remained several inches of activated concrete behind the liner in the In-Core-Instrumentation (ICI) pit. The approved License Termination Plan specified that the activated concrete would be removed to meet the DCGL levels. The reactor pressure vessel was enclosed and shielded by a combination of the primary shield wall and the ICI sump (Figures 8-1 and 8-2). The remediation of this activated concrete was viewed as a significant industrial safety risk and would incur additional personnel radiation exposures inconsistent with the ALARA principle.

A revised plan was developed to remove all concrete to the liner and to leave the liner in place with 6 – 8 inches of activated concrete behind the liner for approximately 20 feet below the neutron shield tank. Calculations showed that only 7% of the activated concrete was below the liner. In order to accomplish this plan, a revision to the License Termination Plan was required. The change revised the concrete basement fill model to allow the additional activated concrete (raising the DCGL for basement concrete) and a reduction in the surface and deep soil DCGL such that the total projected exposures to the resident farmer would not exceed 10 mrem/y through all pathways and 4 mrem/y through the groundwater pathway.

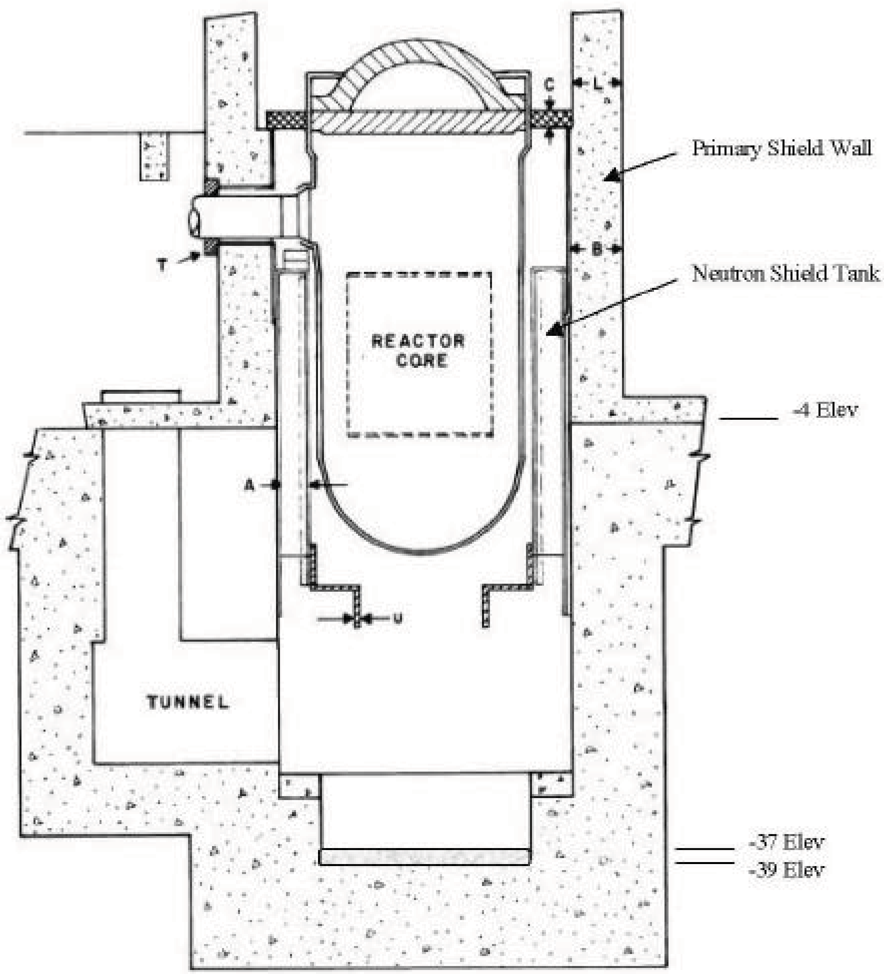


Figure 8-1 Maine Yankee RPV & Shielding

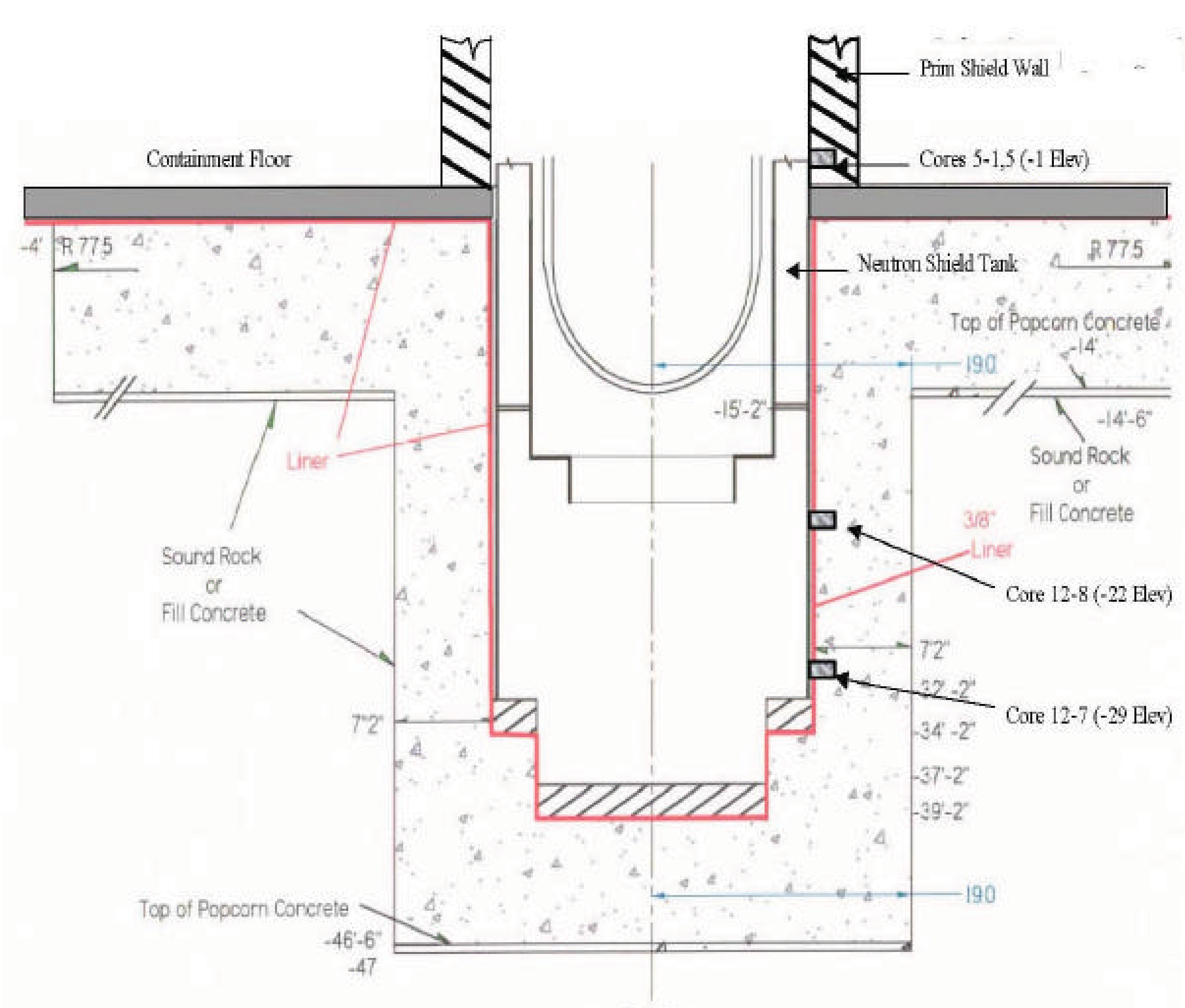


Figure 8-2 Maine Yankee ICI Sump

Forebay and Diffuser Remediation Issues

The Maine Yankee Forebay and Diffuser provided for the intake and discharge of circulating water into the Back River. The forebay prior to remediation is shown in Figure 8-3. The remediation plan called for the forebay to be filled in to a level to allow for the development of a natural highlands marsh (Figure 8-6). The dose model used assumed the dike soil was contaminated to a depth of two feet, and included projected doses from drinking water and irrigation water from the area. Characterization and remediation of the subsurface forebay area was also performed using specialty gamma spectroscopy equipment (Figure 8-4).

Remediation of the forebay required substantial effort. There was a large uncertainty as to the levels and depth of contamination behind the riprap (rocks one to two feet in diameter along the banks of the forebay). A decision was made to perform a boring campaign for approximately one million dollars early on to assess the contaminants and help frame remediation processes

(Figure 8-5). Initial guesses were contaminants up to two feet in depth (based on very minimal sampling). Actual depths based on the borings, were contaminant depths only to about two inches, not two feet. This allowed a large reduction in the remediation conducted on the forebay.

Figure 8-3 Maine Yankee Forebay - Before Remediation

Figure 8-4 Maine Yankee Forebay Characterization and Remediation

Figure 8-5 Maine Yankee Forebay Dike Core Sampling

Figure 8-6 Maine Yankee Forebay After Remediation

Site Boundary Issues

Many different site boundaries may exist at a site depending upon the regulator and the purpose of the regulation. The site boundary is important for many reasons. In decommissioning one objective is to shrink the site to the smallest possible area (either complete elimination of the licensed area or reduced to just the size needed for the ISFSI).

The first site boundary to consider is the boundary as described in the Technical Specifications and/or Updated Final Safety Analysis Report (UFSAR). Research determined that the site boundary at Maine Yankee had changed over time. At one point the site boundary was contained in the Technical Specifications. The site boundary was then removed from the Technical Specifications by license amendment and put into the UFSAR allowing changes to be made without NRC approval under the provisions of 10 CFR 50.59.

The next site boundary to consider is the Exclusion Area Boundary required under the provisions of 10 CFR 100, which in the case of Maine Yankee was changed in early 2004. Altering the location of this boundary becomes less important if the site is able to obtain appropriate exemptions from the site emergency plan early on in the decommissioning process. Reducing the Exclusion Area Boundary may be useful if the reduced boundary allows you to disposition or

sell parcels of buffer zone land early on if you no longer have to "own or control the land". Prior to land disposition, you also need to look at boundaries for security and radiological effluents.

Reducing the Emergency Planning Zone (EPZ) becomes a stakeholder interaction. Maine Yankee gave local municipalities the choice of taking over the funding for emergency sirens or Maine Yankee would pay to have them taken down. During years of operations, Maine Yankee provided a various types of equipment to local municipalities for emergency management. Once the EPZ was reduced in size, the offsite response support was no longer required, however Maine Yankee allowed the municipalities to keep the equipment.

New boundaries were also required in the development of the ISFSI. The boundary required per 10 CFR 72 is at least 100 meters. The ISFSI itself covers about 8.5 acres, but an NRC security design basis threat evaluation led to the establishment of a perimeter extending 300 meters from the ISFSI (about 100 acres) as the controlled area.

Final Site Release Issues

The completion of the actions identified in the LTP presented a continuing need for dialog with the various regulators for Maine Yankee. Similar dialog was needed for the closure actions under the State requirements for non-radiological cleanup. A site specific closure plan was developed in accordance with Resource Conservation and Recovery Act (RCRA) requirement including a Quality Assurance Program Plan. These plans were submitted to Maine DEP for approval and were rigidly reviewed and enforced for site closure. One action specified was the development of a Cumulative Risk Assessment which combined the risks from residual radioactive and non-radioactive contaminants. The Cumulative Risk Assessment for the "Backlands" is provided in Attachment F. The Backlands was the colloquial title for the Eaton Farm and North Ferry Road areas.

The determination of final remediation required for the diffuser piping was another exercise in stakeholder interaction. In the State of Maine, anytime major physical actions take place within 100 feet of a waterway, it triggers the need for a National Resources Permit Act (NRPA) process. NRPA requires that all applicable state and federal agencies with interest in the particular environmental action participate in the determination of the most beneficial end state.

To support the process, Maine Yankee performed a wide range of marine sampling and analysis of the diffuser pipe and identified a number of organisms that lived there. When all agencies provided input, the conclusion for overall environmental betterment was not to remove the diffuser pipe. This is another activity that is best served working on early in the decommissioning process as the outcome can affect the overall decommissioning scope and schedule.

One additional issue regarding LTP implementation is noted. The LTP and the NUREG 1757 state what is required for a final survey record, and Maine Yankee developed the final survey records to meet these two documents. The NRC reviewer(s) would request additional information regarding decommissioning and remediation information, HSA data, and release records. This information was not required by either the Maine Yankee LTP or the NUREG.

Addressing this difference in perceived document requirements took some time to resolve and is still ongoing.

Land Transfer Issues

In the 1999 - 2000 timeframe Maine Yankee began looking at what to do with the site property. The first decision required affected the Eaton Farm area. This was approximately 200 wooded acres that the company used for picnics and as a buffer zone. In the FERC agreement Maine Yankee agreed to the property being donated to a non-profit organization to maintain public access, for conservation, and for environmental education.

Three organizations responded to Maine Yankee's RFP for use of the land. After review of the merits of the bids proposed, Maine Yankee agreed to transfer the Eaton Farm area to the Chewonki Foundation. As of the date of this report, the transfer had not yet concluded.

Another parcel of land transferred was the area identified as North Ferry Road. This 430 acre parcel was the first to be released from the NRC license in July 2002. This parcel was sold on August 5, 2004 to a non-profit development created by the Town of Wiscasset. This entity in turn sold the property to a development company that specializes in redevelopment of "challenging properties". The RCRA release for the area required more effort than the NRC release, primarily due to the existence on the property of a legacy dump. This dump was not from Maine Yankee actions, rather from local individuals.

Maine Yankee retains approximately 100-150 acres which primarily constitutes the Bailey Point peninsula. This area includes the former site industrial area and the current ISFSI.

All potential real estate recipients wanted Maine Yankee to indemnify the property recipients against all nuclear hazards and other contaminants. Maine Yankee worked to educate the potential buyers with the provisions of the 10 CFR 20 license termination requirements. Relative to chemical contaminants, the buyer obtained a "no action" letter by the state saying the state has found the area clean from chemical contaminants.

A substantial amount of data was required to be produced for the potential real estate recipients. Examples of information included LTP surveys, RCRA surveys, routine effluent reports (radiological and chemical) from the plants operating period, overall regulatory performance, etc. Much of the information gathered to address the perception of potential contamination in addition to the survey data to demonstrate the measured residual risk. As a site reduces its required records, and sends some records for long term offsite storage, it is important to recognize the records that may be required for property transfer due diligence and keep these records available for ready access.

Property Taxes

During operations, Maine Yankee was paying approximately $12 million a year to Wiscasset. This represented approximately 93% of the property taxes collected by the municipality.

Historically, the site entered into multi-year agreements as to the tax liability. Following the plant shutdown, the town agreed to a reduction in taxes initially to ~ $6.1 million. Subsequent two year agreements were reached wherein by 2002 the annual tax liability was approximately $1 million.

Additional discussions and negotiations occurred with the town but did not result in further agreement. The local property assessment board, reassessed the property as having a value of approximately $263 million. This assessment was not on the basis of the value of the land itself, but a value based on the fact that the remaining property contained the ISFSI which was the only location in the state that Maine Yankee could store its spent fuel. As such, it was deemed to have very high value.

Maine Yankee's position is that Maine state law indicates property values are determined based on what someone would be willing to pay for the property and on that basis, the ISFSI is certainly not worth $263 million. Maine Yankee formally contested the assessment and current plans provide for a property tax appeal to be heard by the Maine State Tax Board of Property Tax Appeals in February 2005.

9
CURRENT STATUS

At the time this report was written, the only remaining structures at the Maine Yankee site were the ISFSI, two warehouses, an administration building and a few office trailers. The buildings unrelated to the ISFSI would be removed in the near term. The remaining rubble from the containment shell demolition was being shipped offsite. The primary remaining actions are the conclusion of final site survey and project closeout activities. The current plan has all physical work complete by March 2005 with an anticipated license termination by mid 2005.

In addition to the ISFSI operations, actions to complete the RCRA closure for non-radiological contaminants will continue as will the supplemental groundwater monitoring to satisfy an agreement with the State of Maine.

The current estimate of project costs from 1997 to 2005 total approximately $495 million as follows:

Table 9-1
Summary of Project Costs 1997 – 2005

Cost Element	Cost ($ Million)
Major Contracts – Low level waste, demolition, Radiation protection, DOC	298
Maine Yankee labor and staff augmentation	153
Support Contracts (Security, Engineering, Accounting)	49
Fees and Property Taxes	23
Materials and Supplies	11
Insurances	7
Purchased Power	6
Other	11

Settlements from contract disputes	(63)

The project should conclude with a total radiation dose of approximately 525 person-rem (5.25 person-Sv) which is less than 50% of the exposure limit in the decommissioning Generic Environmental Impact Statement. The project had completed over two million safe work hours without a lost time accident. Overall, the project has completed approximately 5.4 million hours with a recordable incident rate of approximately 2.3 per 200,000 hours worked.

10 REFERENCES REVIEWED

In the preparation of this report, many publicly available documents regarding the MYAPC decommissioning project were reviewed. Additional documents were provided by MYAPC. The following list identifies the major sources of information used in the preparation of this report.

1. Central Maine Power (CMP) Economic Study, July 30, 1997, www.maineyankee.com

2. Proceedings from American Nuclear Society Winter Meeting – November, 2002

3. FERC Settlement Agreement – Docket Number ER98-570-000, December 31, 1998 www.maineyankee.com

4. ASLB Settlement Agreement – ASLBP No. 00-780-03-OLA, August 31, 2001

5. Primary meeting minutes from Maine Yankee Community Advisory Panel from August 1997 through June 2004 (Maine Yankee)

6. Maine Yankee Community Advisory Panel Self Assessment Report (Appendix D – Maine Yankee)

7. Maine Yankee newsletter for all on-site personnel, The Look Inside, from September 25, 1997 through September 29, 2004 (Maine Yankee)

8. US NRC Inspection Reports for Maine Yankee from August 1998 through January 20043 (IR 98-04 – 03-03) (www.nrc.gov)

9. The following EPRI Reports (EPRI)
   - EPRI/NEI Decommissioning Workshop 12/97 (TR-110006)
   - EPRI/NEI Decommissioning Workshop 12/98 (TR-111025)
   - EPRI Site Characterization Workshop 12/99 (TR-112876)
   - EPRI Decommissioning Engineering Workshop 10/00 (1001238)
   - EPRI LTP Workshop 10/01 (TR-112871)
   - EPRI/NEI Decommissioning Workshop 4/03 (1008924)
   - EPRI/NEI LTP/Site Release Workshop 9/03

- Evaluation of RCS Decontamination at Maine Yankee and Connecticut Yankee (TR-112092)
- Experience and Testing of Application of DfD Process (TR-112877)
- Decontamination of Reactor Systems and Containment Components (1003026)
- EPRI Reactor Vessel Segmentation Lessons Learned (1003029)
- Spent Fuel Pool Cooling and Cleanup Systems Experience at Decommissioning Plants (1003424)
- Summary of Utility License Termination Documents and Lessons Learned: Summary of License Termination Plans Submitted by Three Nuclear Power Plants (1003426)
- Capturing Historical Knowledge for Decommissioning of Nuclear Power Plants: Summary of Historical Site Assessments at Eight Decommissioning Plants (1009410)

10. Newsletters from the Decontamination, Decommissioning and Reutilization Division of the American Nuclear Society from October 2000 through October 2004

11. The Decommissioning Handbook, ASME, 2004

12. NRC SECY 00-0041 Use of Rubblized Concrete Dismantlement to Address 10 CFR Part 20, Subpart E, Radiological Criteria for License Termination

13. MYAPC PSDAR Public Meeting Transcript – November 6, 1997

14. MYAPC PSDAR – August 27, 1997

15. MYAPC Irradiated Fuel Management Plan – July 19, 1999

16. Cumulative Risk Assessment for Backlands Portion of the Maine Yankee Site – August 2004

A
LISTING OF DECOMMISSIONING TOPICS

The following lists the decommissioning topics to evaluate, ranked in order as to their perceived significance during an EPRI decommissioning workshop held at Connecticut Yankee in September 2004.

First Priority Items

- Regulatory interfaces and challenges
- Project approach (DOC, self perform, etc.) and basis for selection
- Inputs for key decision points (shutdown decision, fuel storage approach)
- Stakeholder interfaces and challenges
- Overall project success drivers
- Technical Challenges

Second Priority Items

- Portion(s) of project contracted and basis for work assignment
- Detailed project cost estimate(s) financial management
- Waste generation by key task (volumes and activity levels)

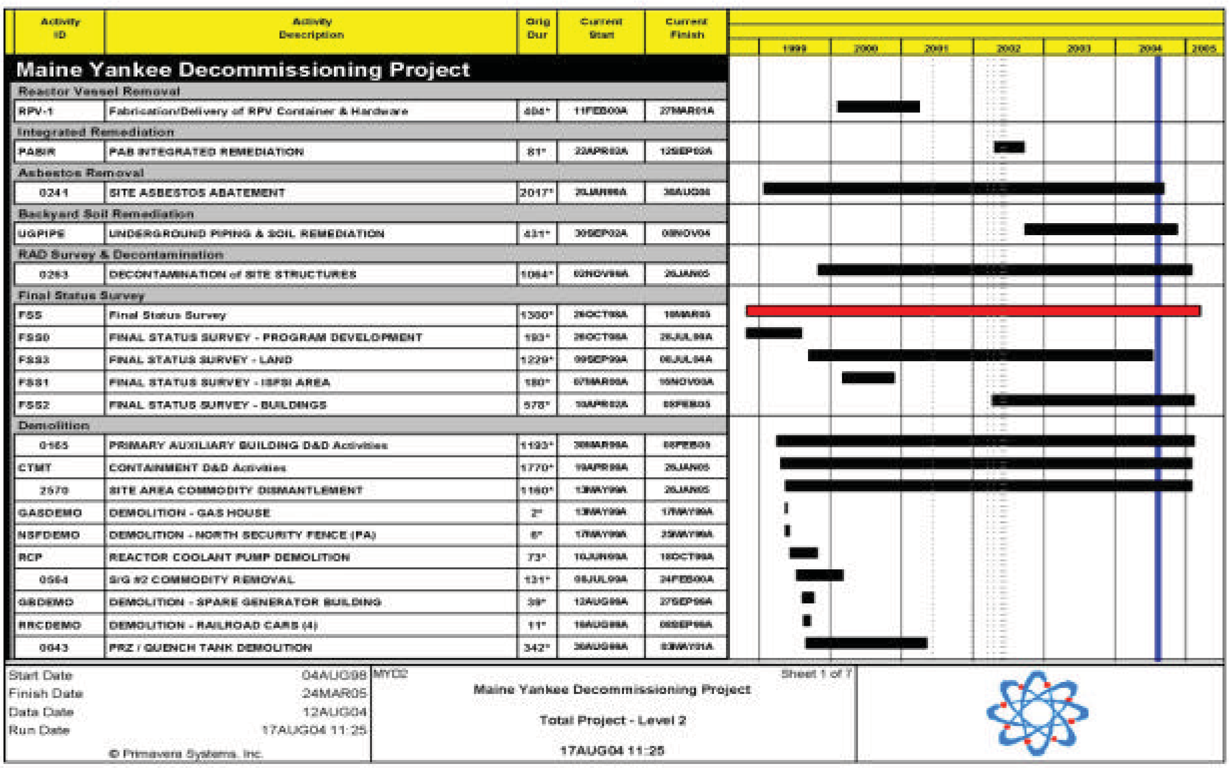
Third Priority Items

- Detailed project planning schedule (level 3)
- Discussion of project delays and basis
- Key contracting lessons
- Worker radiation exposures by key task
- Key administrative challenges

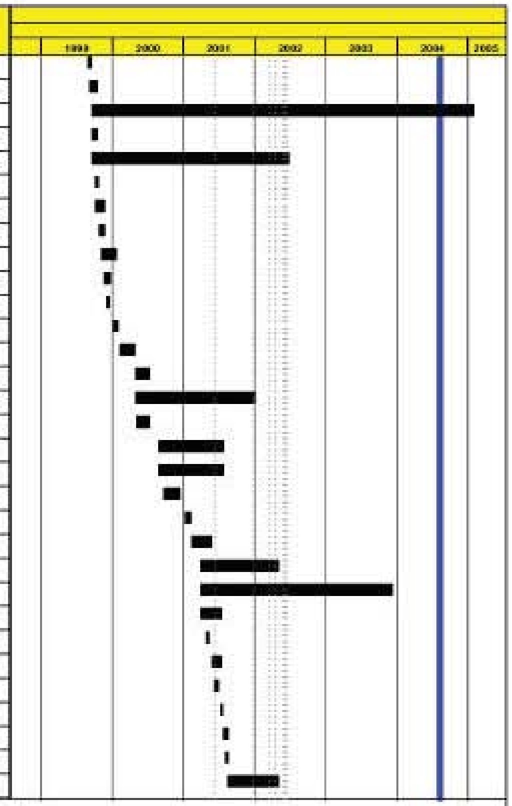
B SUMMARY PROJECT SCHEDULE

The figures in this section represent the project high level schedule from 1999 through 2005 as developed in August 2004.

Figure B-1 Maine Yankee Summary Decommissioning Schedule 1999 - 2005



Activity ID	Activity Description	Orig Dur	Current Start	Current Finish
CSTFDEMO	DEMOLITION - COND STORAGE TANK FOUNDATION	3*	30AUG99A	01SEP99A
FOBDEMO	DEMOLITION - FUEL OIL BUNKER	23*	03SEP99A	08OCT99A
0274	DEMOLITION - SITE SUPPORT BUILDINGS	1091*	15SEP99A	26JAN05
GTDEMO	DEMOLITION - GUARD TOWERS (3)	12*	20SEP99A	07OCT99A
TB-COM	COMMODITIES - TURBINE BUILDING	557*	20SEP99A	18JUN02A
ILRTDEMO	DEMOLITION - RCA WEST (ILRT)	8*	05OCT99A	13OCT99A
X24DEMO	DEMOLITION - STATION TRANSFORMERS X-24/26/28	21*	06OCT99A	10NOV99A
DWSTDEMO	DEMOLITION - DEMIN WATER STORAGE TANK (DWST)	10*	27OCT99A	11NOV99A
L2RCSPC	LOOP 2 RCS PIPE CUTS	38*	08NOV99A	11JAN00A
TTDEMO	DEMOLITION - TEST TANKS	12*	22NOV99A	13DEC99A
WH5DEMO	DEMOLITION - WAREHOUSE #5	3*	01DEC99A	08DEC99A
CB33COM	COMMODITIES - CTMT ELEC PENETRATION ROOMS	8*	10JAN00A	20JAN00A
RWSTDEMO	DEMOLITION - REFUELING WATER STORAGE TANK (RWST)	65*	09FEB00A	13APR00A
CW-COM	COMMODITIES - CIRC WATER PUMPHOUSE	33*	27APR00A	28JUN00A
CW0006	CIRC WATER PUMP HOUSE D&D Activities	333*	27APR00A	24DEC01A
SCATD	DEMOLITION - SPRAY CHEM ADDITION TANK (SCAT)	29*	04MAY00A	25JUN00A
TG0102	DEMOLITION - MAIN TURBINE/GENERATOR	181*	28AUG00A	16JUL01A
TURBDEM	Demo Main Turbine & Generator	181*	28AUG00A	16JUL01A
CONDDEMO	DEMOLITION - MAIN CONDENSER	43*	20SEP00A	05DEC00A
EFWCOM	COMMODITIES - EFW PUMPROOM	12*	10JAN01A	30JAN01A
SBCOM	COMMODITIES - SERVICE BUILDING	56*	12FEB01A	17MAY01A
TB-STR	DEMOLITION - TURBINE BUILDING (Phase I)	213*	04APR01A	23APR02A
TB0006	DEMOLITION-TURBINE BUILDING (PH I & II)	542*	04APR01A	04DEC03A
TBSS	DEMOLITION - TURBINE BUILDING SOUTH SIDE	51*	04APR01A	03JUL01A
WH5SDEMO	DEMOLITION - WAREHOUSE #5 FOUNDATION	4*	23APR01A	09MAY01A
X13DEMO	DEMOLITION - TRANSFORMER X-13 / X-15	20*	29MAY01A	02JUL01A
SPCOM	COMMODITIES - SPRAY BUILDING	7*	11JUN01A	20JUN01A
MET	DEMOLITION - MET TOWER & BUILDING	3*	10JUL01A	12JUL01A
345KV	DEMOLITION - 345KV ELECTRICAL TOWERS	12*	24JUL01A	13AUG01A
CSDEMO	DEMOLITION - COLLECTION SITE	4*	06AUG01A	09AUG01A
SBD1	DEMOLITION - SERVICE BLDG (PHASE 1)	141*	15AUG01A	29APR02A



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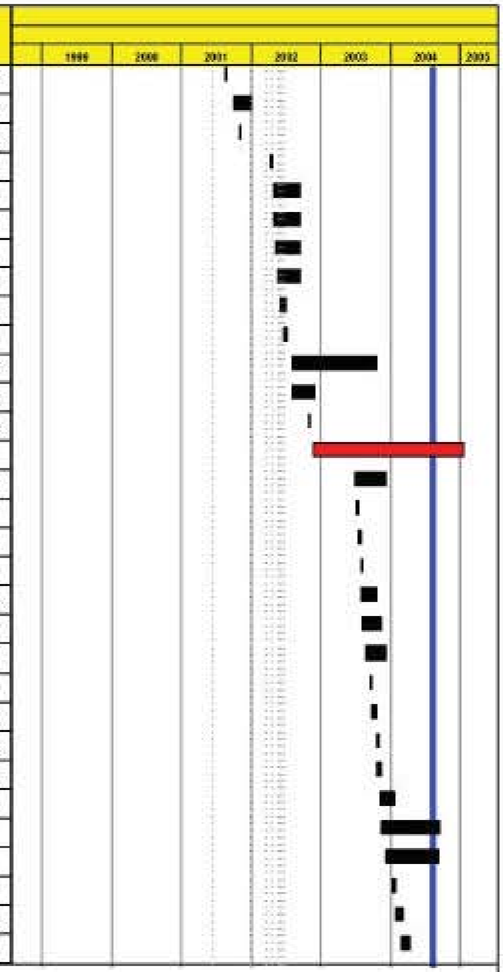
Activity ID	Activity Description	Orig Dur	Current Start	Current Finish
WWPHDEMO	DEMOLITION - WELL WATER PUMPHOUSE	2*	15AUG01A	16AUG01A
CW-STR	DEMOLITION - CIRC WATER PUMPHOUSE	48*	01OCT01A	28DEC01A
STP	DEMOLITION - SEWAGE TREATMENT PLANT	4*	29OCT01A	01NOV01A
GAS	DEMOLITION - GAS HOUSE FOUNDATION	3*	11APR02A	16APR02A
0126	DEMOLITION - REACTOR MCC ROOM	70*	02MAY02A	05SEP02A
RMCC-COM	COMMODITIES - REACTOR MCC ROOM	70*	03MAY02A	05SEP02A
0132	DEMOLITION - STEAM & VALVE HOUSE	67*	08MAY02A	05SEP02A
PHD	DEMOLITION - PERSONNEL HATCH BLDG	60*	21MAY02A	05SEP02A
BLOCK1	DEMOLITION - VEHICLE THREAT BARRIERS	15*	03JUN02A	25JUN02A
INFO	DEMOLITION - INFORMATION CENTER	8*	19JUN02A	02JUL02A
SBD2	DEMOLITION - SERVICE BLDG (PHASE 2)	244*	31JUL02A	11OCT03A
FP	DEMOLITION - FIRE PUMP HOUSE & POND	63*	02AUG02A	20NOV02A
TTFDEMO	DEMOLITION - TEST TANK FOUNDATIONS	3*	28OCT02A	30OCT02A
CTMTD1	DEMOLITION - CONTAINMENT	542*	22NOV02A	18JAN05
TRANS	DEMOLITION - MAIN XFMR FOUNDATIONS	89*	01JUL03A	04DEC03A
SBFDEMO	DEMOLITION - SOFTBALL FIELD	4*	07JUL03A	10JUL03A
BPS	DEMOLITION - BAILEY POINT STORAGE AREA	3*	17JUL03A	22JUL03A
SANDEMO	DEMOLITION - SANITARY LINES	1*	30JUL03A	30JUL03A
WART	DEMOLITION - WART BUILDING	40*	31JUL03A	10OCT03A
ADMIN	DEMOLITION - ADMINISTRATION BUILDING	51*	06AUG03A	04NOV03A
TB-STR2	DEMOLITION - TURBINE BUILDING (Phase II)	56*	27AUG03A	04DEC03A
BAILEY	DEMOLITION - BAILEY HOUSE	3*	16SEP03A	18SEP03A
EFDEMO	DEMOLITION - EATON FARM STRUCTURES	11*	23SEP03A	10OCT03A
HV7	DEMOLITION - HV-7 & 9 BUILDING	4*	20OCT03A	23OCT03A
SPDEMO	DEMOLITION - SPRAY BUILDING	14*	20OCT03A	06NOV03A
PHS	DEMOLITION - PER HATCH BLDG SLAB / BACKFILL	37*	10NOV03A	15JAN04A
115KV	DEMOLITION - 115KV ELECTRICAL TOWERS	168*	12NOV03A	03SEP04
BWST	DEMOLITION - BWST & BERM AREA	151*	03DEC03A	31AUG04
PVS	DEMOLITION - PRIMARY VENT STACK	7*	13JAN04A	21JAN04A
FOXBIRD	DEMOLITION - FOXBIRD ISLAND BUILDING	20*	26JAN04A	25FEB04A
RACKS	SPENT FUEL POOL STORAGE RACK REMOVAL	31*	02MAR04A	06APR04A



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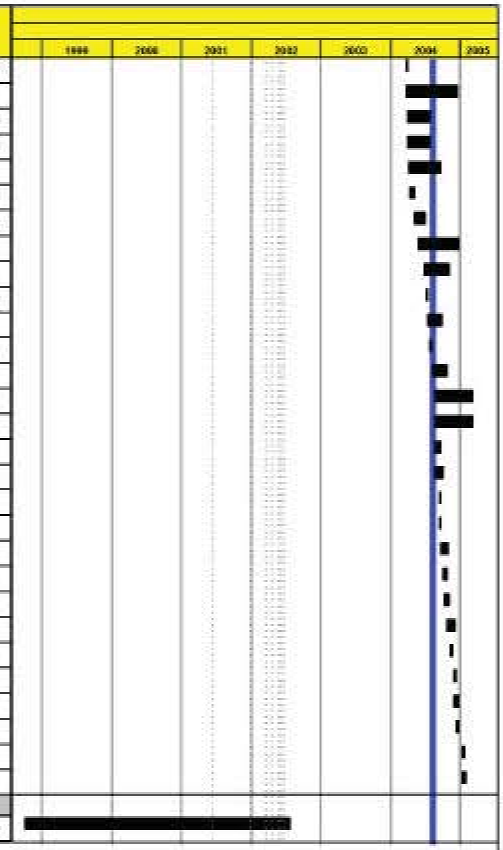
Activity ID	Activity Description	Orig Dur	Current Start	Current Finish
PAGODA	DEMOLITION - SFPI GENERATOR & PAGODA	3*	22MAR04A	24MAR04A
RMCCBF	DEMOLITION - RMCC SUBGRADE & BACKFILL	149*	24MAR04A	14DEC04
PAB-DEMO	DEMOLITION - PRI AUXILIARY BUILDING	67*	29MAR04A	22JUL04A
EFWDEMO	DEMOLITION - EFW PUMPROOM	63*	01APR04A	21JUL04A
LSA	DEMOLITION - LSA STORAGE BUILDING	94*	05APR04A	10SEP04
DWSTF	DEMOLITION - DWST FOUNDATION	8*	15APR04A	26APR04A
CR3HAM	DEMOLITION - FUEL BUILDING CRANE CR-3	30*	05MAY04A	28JUN04A
RPDEMO	DEMOLITION - SITE ROADS & PARKING LOTS	117*	25MAY04A	20DEC04
FENCE	DEMOLITION - SECURITY FENCE	71*	25JUN04A	20OCT04
RWSTFN	DEMOLITION - RWST/SCAT FOUNDATION	1*	08JUL04A	08JUL04A
RCA	DEMOLITION - RCA STORAGE BUILDING	41*	14JUL04A	23SEP04
TPDEMO	DEMOLITION - TEST PIT	1*	25JUL04A	25JUL04A
X14	DEMOLITION - TRANSFORMER X-14/16 AREA	35*	12AUG04	13OCT04
0280	Final Site Grading	110	23AUG04	03MAR05
0280-HAM	FINAL SITE GRADING & LANDSCAPING	110*	23AUG04	03MAR05
PWSTDEMO	DEMOLITION - PRI WATER STORAGE TANK	14*	23AUG04	15SEP04
0250	DEMOLITION - SFP BUILDING	19*	24AUG04	27SEP04
GT1	DEMOLITION - GUARD TOWERS FOUNDATIONS	1*	15SEP04	15SEP04
TPSDEMO	DEMOLITION - TEMP POWER SHACK	1*	16SEP04	16SEP04
FHDEMO	DEMOLITION - FIRE HYDRANTS/HOSE STATIONS	19*	20SEP04	20OCT04
LSDEMO	DEMOLITION - LIFT STATION	8*	05OCT04	13OCT04
WH23DEMO	DEMOLITION - WAREHOUSE #2/3	12*	11OCT04	26OCT04
SFDEMO	DEMOLITION - STAFF BUILDING	22*	20OCT04	29NOV04
PWDEMO	DEMOLITION - POTABLE WATER CONNECTION	4*	10NOV04	16NOV04
LPDEMO	DEMOLITION - UTILITY LIGHT POLES	5*	30NOV04	07DEC04
OUDEMO	DEMOLITION - OUTSIDE UTILITIES	12*	30NOV04	20DEC04
WH4DEMO	DEMOLITION - WAREHOUSE #4 (Annex)	4*	13DEC04	16DEC04
MODDEMO	DEMOLITION - MODULAR OFFICES	4*	11JAN05	17JAN05
RRDEMO	DEMOLITION - RAILROAD TRACKS	10*	11JAN05	26JAN05
ISFSI (Independent Spent Fuel Storage Install.)				
ISFS52	Licensing - Federal (HA)	771*	01OCT98A	15JUL02A



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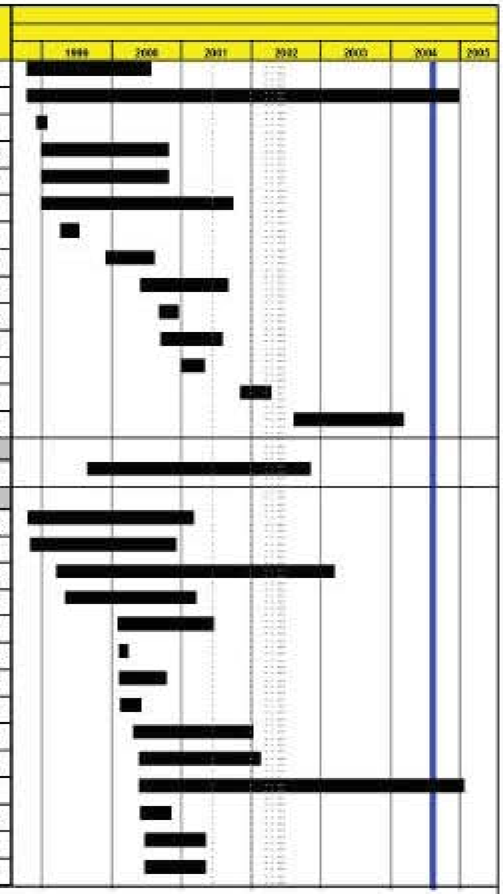
Activity ID	Activity Description	Orig Dur	Current Start	Current Finish
ISFS51	Site Selection (HA)	361*	12OCT98A	13JUL00A
ISF865	Cask Vendor Licensing (Storage & Transport) (HA)	1256*	16OCT98A	16DEC04
1008	Detailed Engineering and Design (HA)	31*	01DEC98A	14JAN99A
1073	Supply fab drawings, Specs & Procedures (HA)	461*	28DEC98A	13OCT00A
1074	MYPS Review - Drawings, Specs, & Procs (HA)	461*	28DEC98A	13OCT00A
ISFS66	Cask Vendor Eng/Design (HA)	556*	28DEC98A	19SEP01A
1104	Finish Inventory Fuel Pool (Std Fuel) Insp (HA)	82*	07APR99A	03JUL99A
1141	ISFSI Construction Phase I (HA)	138*	20NOV99A	01AUG00A
1142	ISFSI Construction Phase II (HA)	313*	31MAY00A	22AUG01A
VCCFAB-HAM	GTCC VCC Construction Units 1 thru 4	75*	05SEP00A	02DEC00A
PHIIC-60	Construct Security/Ops Bld Mods - ISFSI Phase II	389	15SEP00A	23JUL01A
VCCFAB-WIN	WINTER DEMOB & LAY-UP (VCC Construction)	112	01JAN01A	22APR01A
GTCCLOAD	Load & Transfer GTCC Casks to ISFSI	150*	06NOV01A	04APR02A
FUELLOAD	LOAD & TRANSFER 60 FUEL CASKS TO ISFSI	562*	12AUG02A	27FEB04A
ISFSI Licensing				
CVLT-SF	Cask Vendor Licensing Transport (Standard Fuel)	806*	01SEP99A	31OCT02A
Licensing				
CVLS-NS	NAC-UMS Storage (Non-Standard Fuel)	596*	20OCT98A	20FEB01A
CVLS-HAM	Cask Vendor Licensing Storage (Standard Fuel)	525*	02NOV98A	29NOV00A
DD0101	License Termination Plan Approved by NRC (HA)	1003*	22MAR99A	28FEB03A
CN2000	Regulatory Approvals (HA)	470*	30APR99A	09MAR01A
0700-LIC	Dev & Implement Transitional Training Progr (HA)	272*	02FEB00A	06JUN01A
0033-LIC	ISFSI Application (Rev.1) (MDEP & Wiscasset (HA)	21*	07FEB00A	13MAR00A
CVLT-NS	NAC-UMS Transport Amendment I (Non-Standard Fuel	188*	09FEB00A	04OCT00A
SEC-290	Security 72.212 (b)(5) Exemption Request	55*	19FEB00A	24MAY00A
CVLS-NS2	NAC-UMS Storage Amendment II (Non-Standard Fuel)	427*	24APR00A	31DEC01A
ITS-HAM	ISFSI & Dismantlement Tech Specs (HA)	433*	23MAY00A	09FEB02A
ROB-HAM	Release of Backlands (HA)	1179*	22MAY00A	11JAN05
PLAN-100	FUEL IN TRANSIT E-PLAN (HA)	82*	01JUN00A	25OCT00A
SEC-180	ISFSI SECURITY PLANNING PROCEDURE CHANGES (HA)	170*	22JUN00A	26APR01A
SEC-420	ISFSI SECURITY PROCEDURES (HA)	170*	22JUN00A	26APR01A



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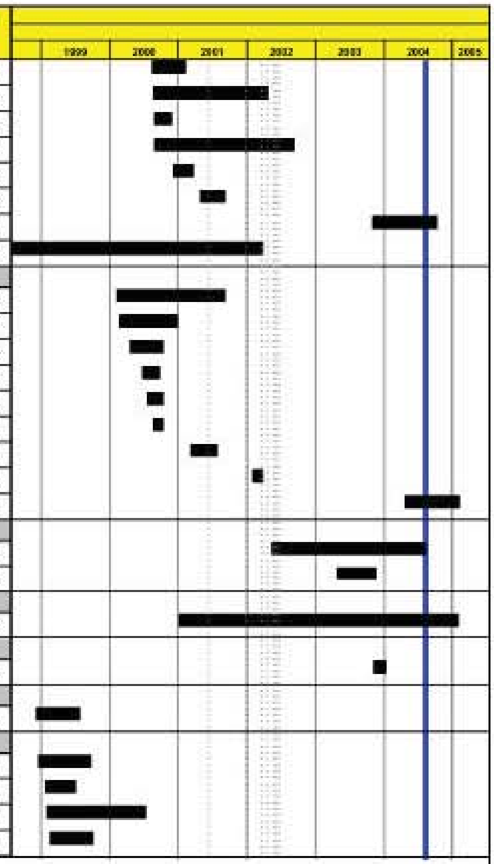
Activity ID	Activity Description	Orig Dur	Current Start	Current Finish
0800-OPS	ISFSI Operating Procedures (HA)	93*	14AUG00A	25JAN01A
0600-HAM	Part 72 Specific License for ISFSI (Not Pursued)	335*	22AUG00A	17APR02A
PLAN-210	FUEL IN TRANSIT E-PLAN PROCEDURES (HA)	47*	24AUG00A	15NOV00A
PLAN-400	ISFSI EMERGENCY PLAN (STAND-ALONE)	514*	25AUG00A	04SEP02A
PLAN-280	FUEL IN TRANSIT E-PLAN LESSON PLANS/TRAINING (HA	55*	04DEC00A	12MAR01A
SEC-250	ISFSI SECURITY TRAINING (HA)	71*	24APR01A	28AUG01A
ROS-HAM	Release of Site Lands: Remaining Non-ISFSI Land	234*	03NOV03A	01OCT04
0489-LIC	Plan Special Circumstance Discharges (HA)	4087*		14MAR02A
Environmental Permitting				
0300-HAM	RCRA Closure Plan (External) (HA)	315*	10FEB00A	31AUG01A
0100-HAM	Building Demolition Assessment (HA)	164*	23FEB00A	14DEC00A
0700-CPR	PCB Concrete Paint Removal Plan (HA)	90*	20APR00A	03OCT00A
0700-HAM	Concrete Characterization of CRS/Scarborough (HA	48*	26JUN00A	14SEP00A
CD-HAM	Concrete Disposition (HA)	41*	20JUL00A	02OCT00A
0900-HAM	ISFSI Concrete Characterization (HA)	23*	23AUG00A	03OCT00A
0600-NRPA	NRPA & Corps of Engineers Permit (HA)	76*	07MAR01A	19JUL01A
FPHEP	FIRE PUMP HOUSE ENVIRONMENTAL PERMITTING	24*	04FEB02A	14MAR02A
LIC-HAM	Termination of Licenses & Permits	161*	22APR04A	03FEB05
Forebay Remediation				
FOREBAY	DEMOLITION - FOREBAY & SEAL PIT	449*	16MAY02A	30JUL04A
FBAY-REM	FOREBAY & SEAL PIT REMEDIATION	113*	28APR03A	12NOV03A
Waste Disposal				
HP-2	HP Support Routine Duties Outside of CTMT	1461*	02JAN01A	26JAN05
Neutron Shield Tank Demolition (21)				
NST	NEUTRON SHIELD TANK DEMOLITION (C/P)	43*	08NOV03A	31DEC03A
Decommissioning Readiness				
0798	Plant Prep & Temp Services (HA)	130*	01DEC98A	15JUL99A
7574				
ISFS59	Architectural Engineering and Design	154*	15DEC98A	13SEP99A
ISFS60	Radiological Analysis	38*	26JAN99A	23JUN99A
ISFS62	Engineering & Design - Plant Upgrades	290*	01FEB99A	30JUN00A
ISFS56	Electrical/Controls & Security Eng. & Design	124*	16FEB99A	22SEP99A



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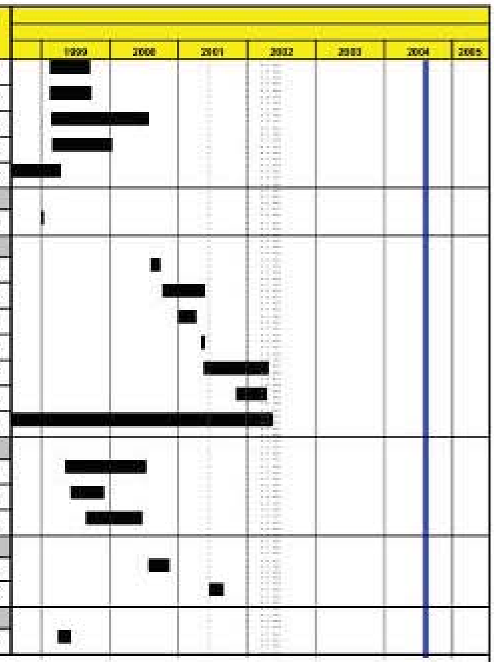
Activity ID	Activity Description	Orig Dur	Current Start	Current Finish
ISFS54	Geotechnical Engineering and Design	112*	19FEB99A	02SEP99A
ISFS57	Mechanical Engineering and Design	115*	19FEB99A	09SEP99A
ISFS64	Local Permitting	282*	22FEB99A	10JUL00A
ISFS30	Structural Engineering and Design	173*	01MAR99A	30DEC99A
ISFS53	QA Plan and Design Criteria	3303*		29MAR99A
B501				
DD0183	Transition Security	1*	04JAN99A	04JAN99A
RPV Internal Segmentation				
SEG-1	Framatome Equipment Assembly and Testing	35*	09AUG00A	13SEP00A
VESSEL	Rx Vessel Internals Segmentation	175*	09OCT00A	09MAY01A
SEG-4	Thermal Shield / CSB Segmentation	84*	29DEC00A	23MAR01A
SEG-10	GTCC Segmentation	9*	01MAY01A	09MAY01A
SEG-13	Final Cavity Clean and Drain	332*	13MAY01A	15APR02A
SEG-11	Load GTCC and Transfer to ISFSI	147*	06NOV01A	04APR02A
SEG-12	Teardown and Final Packout of Cavity Equipment	7066*		08MAY02A
Large Component Removal				
0791	Steam Generators (HA)	233*	10MAY99A	28JUN00A
0789	Reactor Coolant Pumps & Motors	89*	16JUN99A	15NOV99A
0790	Pressurizer (HA)	160*	30AUG99A	13JUN00A
Reactor Vessel Head Removal				
HEAD-PH1	RPV Head Removal to Outside Laydown Area	98*	29JUL00A	01NOV00A
HEAD-PH2A	RPV Head Cut / Rig / Transport to Envirocare	63*	14JUN01A	16AUG01A
Source Term Reduction				
PABS	PAB SOURCE TERM REDUCTION	33*	30MAR99A	25MAY99A



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C PROJECT TIMELINE

This appendix provides a detailed timeline of events during the Maine Yankee decommissioning project and includes a high level summary schedule of the entire project as it existed in August 2004.

Table C-1 Maine Yankee Project Timeline

Date	Event
October 21, 1968	Construction permit issued
September 12, 1972	Provisional operating license issued
December 28, 1972	Commercial Operations begin
June 29, 1973	Full power operating license received
December 6, 1996	Last commercial operations. Maine Yankee shut down the plant as a result of design basis implementation concerns associated with cable separation and control logic issues.
December 18, 1996	The NRC issued a confirmatory action letter requiring need for mid-cycle inspections to check for potential further deterioration, and the overall condition of the steam generators. Engineering staff indicated that while the generators should last 3 more fuel cycles, there could be no assurance that they would not need to be replaced after that.
January 29, 1997	NRC placed Maine Yankee on the NRC watchlist.
January 30, 1997	The NRC issued a supplemental confirmatory action letter requiring resolution of additional concerns ("extent of condition") before startup. Maine Yankee to remain shutdown until resolution of those problems requiring shutdown were accepted by the NRC.
February 13, 1997	One year management contract with Entergy signed.
March 7, 1997	Submittal of Restart Plan to the NRC
May 1997	Maine Yankee Board of Directors decide that plant will either be sold or enter decommissioning

July 30, 1997	Maine Yankee Board of Directors complete economic analysis for shutdown
August 6, 1997	Decision to terminate commercial operations
August 7, 1997	NRC notified of permanent cessation of operations and permanent defueled status
August 21, 1997	First meeting of CAP
August 27, 1997	Post Shutdown Decommissioning Activities Report issued
October 30, 1997	Maine Yankee and Wiscasset finalize agreement on property tax for 1998
October 1997	Initial Characterization Surveys (ICS) begins
November 5, 1997	Maine Yankee files rate case with FERC to increase decommissioning collections
November 6, 1997	PSDAR public meeting
November 6, 1997	Maine Yankee continues management contract with Entergy to provide management services during decommissioning
December 10, 1997	Maine Yankee conducts press briefing onsite for reporters and photographers
January 28, 1998	Maine Yankee submits QA program changes to NRC
February 5, 1998	Maine Yankee submits defueled safety analysis report (DSAR) to NRC
March 1998	RCS decontamination occurs. Asbestos remediation begins
April 17, 1998	DOC RFP issued by Maine Yankee
April 29, 1998	Initial Characterization Surveys completed and report finalized
April 1998	Public opinion poll taken for spent fuel storage options
May 29, 1998	DOC bids are due to Maine Yankee
May 1998	SFPI begins operation
June 2, 1998	Maine Yankee files suit against DOE in court of claims for failure to accept and remove spent fuel
June 24, 1998	Initial CAP meeting regarding SFPI fan noise
August 4, 1998	SWEC chosen as DOC
September 23, 1998	CAP all day planning meeting

September 30, 1998	SFPI fan modifications completed
October 15, 1998	Transition to new control room completed
October 30, 1998	All mechanical systems abandoned
December 30, 1998	Plant achieves “cold and dark” status
December 1998	Asbestos abatement project complete
January 19, 1999	FERC case settlement
March 22, 1999	Source term reduction begins
March 1999	Maine Yankee meets with Wiscasset Planning Board regarding ISFSI construction
April 5, 1999	Fuel inspection begins
May 27, 1999	Source term reduction program complete
May 1999	Maine Yankee submits permit application to Maine BEP for ISFSI construction
June 7, 1999	Emergency diesel generators purchased by a midwest utility
June 1999	First Reactor Coolant Pump removed
July 3, 1999	Fuel inspection completed
July 14, 1999	Maine Yankee and Wiscasset reach agreement on property taxes for 1999 and 2000
September 17, 1999	Maine Yankee proposes rubblization approach to remediation to CAP
September 1999	Maine Yankee files suit against Maine DEP on radiological jurisdiction for ISFSI
October 21, 1999	CAP meeting with NRC and EPA to address LTP and site release criteria
October 1999	All three reactor coolant pumps shipped by rail to Barnwell low level waste site. Reactor coolant pump motors shipped to Envirocare of Utah. Site main power transformers shipped offsite by barge to Midwest utility
December 1, 1999	Maine Yankee received three proposals for use of Eaton Farm
December 1999	Final status surveys begin on property south of Ferry Road
January 13, 2000	Revision 0 to License Termination Plan submitted to NRC – includes agreement to meet 10 mrem/y all pathways and 4 mrem/y groundwater release criteria
March 2000	SWEC decommissioning vice president and construction manager leave Maine Yankee to move to other projects. State of Maine legislation introduced that would require state

	oversight of radiological issues and specify a 0.05 mrem/y residual contamination limit
April 6, 2000	Pressurizer removed
April 26, 2000	State of Maine Law LD 2688-SP1084 signed into law mandating an unrestricted release criteria of 10 mrem/yr for all pathways and 4 mrem/yr for the groundwater pathway
May 4, 2000	SWEC contract terminated and Federal Judge rules that Maine BEP does not have radiological jurisdiction for ISFSI
May 15, 2000	NRC LTP public meeting
June 2000	State of Maine and FOTC petition the NRC to intervene in LTP amendment request
July 2000	Maine Yankee receives construction permits for ISFSI
September 2000	ISFSI construction begins
November 2000	Reactor pressure vessel internals segmentation begins
January 2001	Maine Yankee to self perform decommissioning
February 2001	RCRA Closure Plan submitted to State of Maine
July 2001	Revision 1 to LTP submitted – no longer included rubblization – fuel transfer to ISFSI scheduled from 9/01 to 11/02
August 2001	Revision 2 of the LTP submitted to the NRC
August 30, 2001	Agreement reached in ASLB settlement proceedings
January 2002	Transfer of GTCC from SFPI to ISFSI begins
April 2002	RPV to be removed summer 02 – sent to Barnwell. SF transfer to ISFSI scheduled from 5/02 – mid 2003. All GTCC waste in DCS at ISFSI.
July 2002	North Ferry Road parcel released from NRC license
August 24, 2002	Spent fuel begins transfer from SFPI to ISFSI
August 2002	RPV removed from containment - stored onsite until 2003 for shipment to Barnwell. Delay for shipment due to low water levels in the Savannah River precluding barge traffic to Barnwell site.
October 15, 2002	License Termination Plan, Revision 3 submitted
January 2003	NAC contract terminated and MY to self perform fuel movement/transfer to ISFSI
April 22, 2003	NAC and MY reach new contract agreement for NAC to continue to provide DCS hardware

	hardware
April 2003	Test blast occurs to validate explosive demolition models and calculations
May 6, 2003	MY RPV leaves site for Barnwell
November 2003	Maine Yankee received approval on records disposition exemption request
February 27, 2004	All spent fuel now on ISFSI pad
August 5, 2004	North Ferry Road parcel sold to Wiscasset for redevelopment
September 17, 2004	Explosive demolition of containment shell

D PROJECT RADIATION EXPOSURES

When the Maine Yankee PSDAR was issued in August, 1997 the projected radiation exposure for the project was 946 person-rem (9.46 person-Sv). The License Termination Plan, Revision 3, issued in October 2002 noted the projected exposure to be approximately 937.5 person-rem (9.375 person-Sv). Information on the actual exposures received during detailed decommissioning tasks was not readily available for this document, however the following information from the License Termination Plan provides estimated exposures for a number of decommissioning tasks.

Table D-1 Maine Yankee Projected Radiation Exposures for Project

Area/Activity	Title	Exposure
DC.2 PERIOD 2 (DECOMMISSIONING) **DC.2.01 NSSS REMOVAL** DC.2.01.01 Reactor coolant piping DC.2.01.02 Pressurizer relief tank DC.2.01.03 Reactor coolant pumps and motors DC.2.01.04 Pressurizer DC.2.01.05 Steam Generators DC.2.01.06 CRDMs & service structure removal DC.2.01.07 Reactor vessel internals DC.2.01.08 Reactor vessel		93.951 REM

DC.2.03 SYSTEM REMOVAL		
DC.2.03.01 Containment		
DC.2.03.01.01 Cbl-1	CTMT Loop #1	97.114 REM
DC.2.03.01.02 Cbl-2	CTMT Loop #2	65.745 REM
DC.2.03.01.03 Cbl-3	CTMT Loop #3	63.171 REM
DC.2.03.01.04 Cbl-4	SI Tank #2 & Regen Ht Exch E-67	11.592 REM
DC.2.03.01.05 Cbl-5	CTMT -2 Lvl Pressurizer Area	25.411 REM
DC.2.03.01.06 Cbl-6	CTMT -2 Lvl Sump Pump Area	22.608 REM
DC.2.03.01.07 Cbl-7	CTMT Iodine Filter Area	6.485 REM
DC.2.03.01.08 Cbl-8	CTMT -2' Outer Annulus	43.334 REM
DC.2.03.01.09 CB2-1	CTMT 20' Outer Annulus	19.313 REM
DC.2.03.01.10 CB3-1	Reactor Cavity Area	19.615 REM
DC.2.03.01.11 CB3-2	CTMT Cavity Upender Pit	26.683 REM
DC.2.03.01.12 CB3-3	CTMT 46' Penetration Room	6.078 REM
DC.2.03.01.13 CB3-4	CTMT Polar Crane (CR-1)	4.042 REM
DC.2.03.01.14 CCG	CTMT Charging Floor	3.105 REM
DC.2.03.01.15 CEHO	CTMT Equip Hatch Outer (PE-3)	3.871 REM
DC.2.03.01.16 CICI L	CTMT Incore Instrument Sump	6.533 REM
DC.2.03.01.17 CPHO	CTMT Personal Hatch Outer Area	.728 REM
DC.2.03.01.18 CPLE	CTMT Elevator & Room	.173 REM
DC.2.03.02 PRIMARY AUXILIARY BUILDING		
DC.2.03.02.01 P21A	PAB 21' Level Valve Alley	.742 REM
DC.2.03.02.02 P21B	PAB 21' Boric Acid Pump Area	6.387 REM
DC.2.03.02.03 P21C	PAB 21' Charging Pump Cubicle	22.718 REM
DC.2.03.02.04 P21D	PAB 21' Level Degas Cubicle	9.160 REM
DC.2.03.02.05 P21E	PAB 21' Evap Cubicle	39.169 REM
DC.2.03.02.06 P21H	PAB 21' Heat Exchanger Room	16.495 REM
DC.2.03.02.07 P21L	PAB 21' General Area	1.418 REM
DC.2.03.02.08 P21S	PAB 21' Sample Sink Area	2.799 REM
DC.2.03.02.09 P21V	PAB 21' Level HPSI Room	.956 REM
DC.2.03.02.10 PLAD	PAB Lower Lvl Aerated Drain Tank Area	22.184 REM
DC.2.03.02.11 PLBA	PAB Lower Lvl Boric Acid Mix Tank Area	13.790 REM
DC.2.03.02.12 PLCP	PAB Lower Lvl Aux Chrg Pump Cubicle	5.054 REM
DC.2.03.02.13 PLDC	PAB Lower Lvl Degas Cubicle	1.551 REM
DC.2.03.02.14 PLEC	PAB Lower Lvl Evap Cubicle	13.751 REM
DC.2.03.02.15 PLLA	PAB Lower Lvl Letdown Area	38.761 REM
DC.2.03.02.16 PLPA	PAB Lower Lvl Ctmt Penetration Area	28.907 REM
DC.2.03.02.17 PLPD	PAB Lower Lvl Primary Drain Tank Area	11.122 REM
DC.2.03.02.18 PLPT	PAB Lower Lvl Pipe Tunnel	30.815 REM
DC.2.03.02.19 PLPW	PAB Lower Lvl Primary Water Pump Area	.289 REM
DC.2.03.02.20 PU48	PAB Upper Lvl FN-48 Area	.485 REM
DC.2.03.02.21 PUDD	PAB Upper Lvl Decay Drum Cubicle	.512 REM
DC.2.03.02.22 PUEC	PAB Upper Lvl Evap Cubicle	5.921 REM

DC.2.03.02.23 PUFN	PAB Upper Lvl FN-1A/B Area	.506 REM
DC.2.03.02.24 PUHV	PAB Upper Lvl Heat & Ventilation	.383 REM
DC.2.03.02.25 PUL	PAB Upper Lvl General	1.741 REM
DC.2.03.02.26 PUSA	PAB Upper Lvl Radioactive Storage Area	.316 REM
DC.2.03.02.27 PUTC	PAB Upper Lvl VCT Cubicle	.529 REM
DC.2.03.02.28 PUWG	PAB Upper Lvl Waste Gas Cubicle	.279 REM
DC.2.03.04 SERVICE/FUEL BUILDING		
DC.2.03.04.01 DWST	Demineralizer Water Storage Tank (TK-21)	.103 REM
DC.2.03.04.02 EFPR	Emergency Feed Water Pump Room	.159 REM
DC.2.03.04.04 LSAB	LSA Storage Building	.628 REM
DC.2.03.04.05 NFLA	New Fuel Laydown Area / Fuel Vault	1.622 REM
DC.2.03.04.07 RCAW	RCA Waste Solidification	8.772 REM
DC.2.03.04.08 RMCC	Reactor MCC Room	.046 REM
DC.2.03.04.09 SBDR	Service Building Decon Room	.314 REM
DC.2.03.04.10 SBHP	Service Building HP Checkpoint	.044 REM
DC.2.03.04.11 SBMS	Service Building Machine Shop	.293 REM
DC.2.03.04.13 SBSR	Service Building Seal Room	.111 REM
DC.2.03.04.16 SFP	Spent Fuel Pool	32.159 REM
DC.2.03.04.17 SFPH	Spent Fuel Pool Heat Exchanger Room	9.120 REM
DC.2.03.04.18 SFPV	Spent Fuel Pool Ventilation Room	.287 REM
DC.2.03.04.19 SPRB	Spray Building	78.093 REM
DC.2.03.04.20 SVH	Steam & Valve House	.054 REM
DC.2.03.05 Miscellaneous		
DC.2.03.05.01 BWST	Boron Waste Storage Tanks (TK-13 A&B)	.162 REM
DC.2.03.05.02 CST	Condensate Surge Tank (TK-122)	.003 REM
DC.2.03.05.08 HRB	High Radiation Bunker	.528 REM
DC.2.03.05.09 PWST	Primary Water Storage Tank (TK-16)	.068 REM
DC.2.03.05.10 RWST/SCAT	RWST/SLAT Tanks	1.549 REM
DC.2.03.05.13 West - RCA	RCA Yard Area - West Side	7.136 REM

E PROJECT WASTES

The following data represents a summary of project wastes (radioactive and non-radioactive) from the start of the project (shipments beginning in 1998) through January 2005. Table E-1 below summarizes the waste shipments offsite on a yearly basis for radioactive and non-radioactive wastes by waste category and provides the number of truck and rail shipments required to transport the waste.

Figures E-1and E-2 which follows graphically shows the weight of radioactive and non-radioactive wastes shipped each month from 1998 through January 2005.

Table E-1 Summary of Maine Yankee Waste Shipped 1998 - 2005

SUMMARY TABLE - TOTAL WASTE SHIPPED OFFSITE										
(all weights are in pounds)										
					Totals					
Category	1998*	1999	2000	2001	2002	2003	2004	2005	To-Date	Projected
Non-Radioactive										
Asbestos	199,004	0	15,740	235,100	200	0	0	0	450,044	546,000
Other		1,765	8,405	15,293	5,445	0	0	0	30,908	36,293
Hazardous Waste		4,848	14,079	140,618	10,626	965	3,500	0	174,636	249,512
Oil		7,830	3,927	19,014	5,300	8,664	0	0	44,735	50,307
Paper/ Cardboard		32,294	34,246	35,605	32,200	24,500	20,000	0	178,845	500,000
Trash		188,250	290,050	260,000	212,020	181,000	83,000	4,000	1,218,320	1,326,867
Concrete		0	27,300	19,002,660	35,246,440	16,768,340	15,000,000	3,768,000	89,812,740	104,000,000
Soil		0	3,951,285	137,454	956,000	18,000	1,600,000	0	6,662,739	12,000,000
Demolition Debris	40,940	526,740	1,558,580	906,560	1,705,040	2,932,000	65,000	0	7,734,860	10,000,000
Metal		2,059,720	3,745,814	10,866,357	3,870,040	1,600,200	0	0	22,142,131	23,000,000
Total	239,944	2,821,447	9,649,426	31,618,661	42,043,311	21,533,669	16,771,500	3,772,000	128,449,958	151,708,979
Radioactive										
Concrete	0	0	1,945,790	1,601,610	14,952,424	34,838,550	82,471,195	4,151,900	139,961,469	145,291,000
Soil		0	0	0	117,800	1,919,900	38,868,414	8,628,510	49,534,624	72,395,000
Commodities	0	1,286,771	2,092,783	2,201,350	1,895,400	2,703,690	7,487,899	1,648,200	19,316,093	20,000,000
Distributables	0	455,716	688,385	633,900	317,725	431,375	466,500	0	2,993,601	3,000,000
Large Components	305,560	568,380	2,342,310	152,540	231,508	1,900,000	0	0	5,500,298	5,500,298
Total	305,560	2,310,867	7,069,268	4,589,400	17,514,857	41,793,515	129,294,008	14,428,610	217,306,085	246,186,298
Total	545,504	5,132,314	16,718,694	36,208,061	59,558,168	63,327,184	146,065,508	18,200,610	345,756,043	397,895,277
Total without concrete										148,604,277
Truck Shipments	**1998***	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**To-Date**	
NonRad Truck Shipments	64	168	335	680	355	224	82	4	1,912	
Rad Shipments	21	63	96	102	30	10	7	1	330	
Total	85	231	431	782	385	234	89	5	2,242	
Train Shipments	**1998***	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**		**To-Date**	
NonRad Train Shipments	0	0	0	16	29	10	21	3	79	
Rad Shipments	0	0	5	11	28	40	67	8	159	
Total	0	0	5	27	57	50	88	11	238	
	*1998 data only includes asbestos abatement work									
	Note: Large components include SGs, Pressurizer, RCP pumps & motors, RPV & internals, and 1998 asbestos removal project									

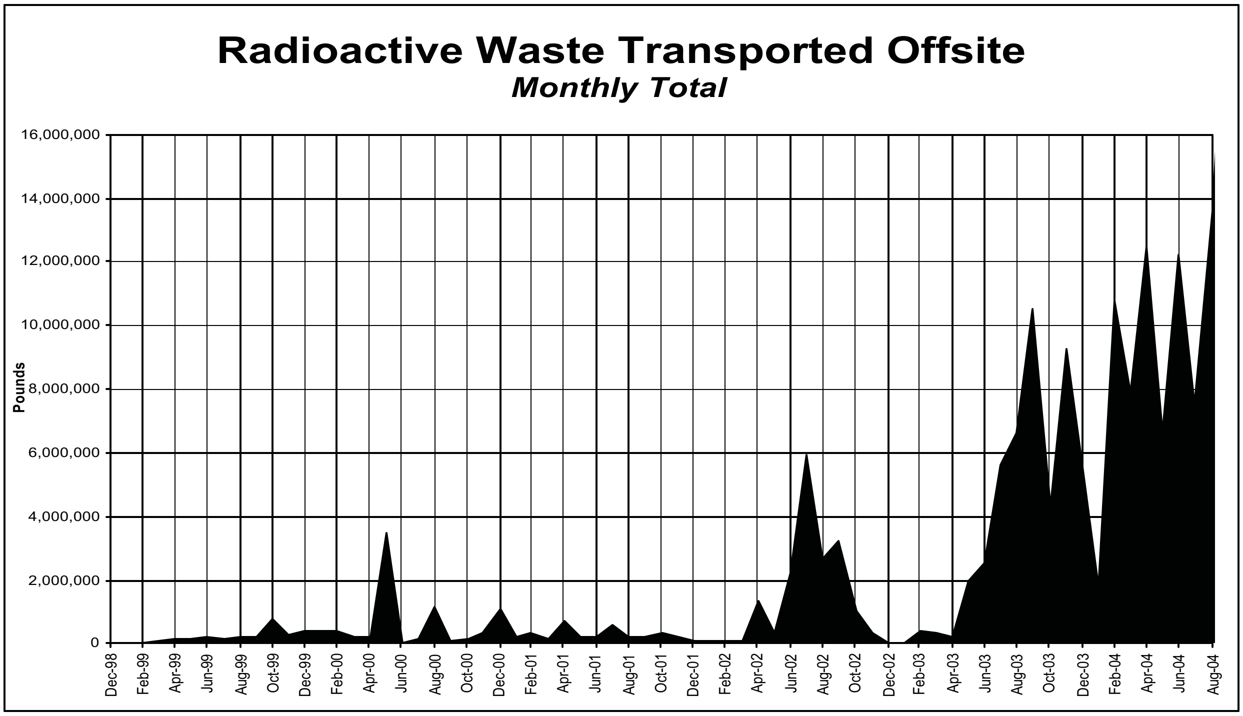

Figure E-1 Maine Yankee Radioactive Waste Shipments - Monthly Totals 1998 - 2004

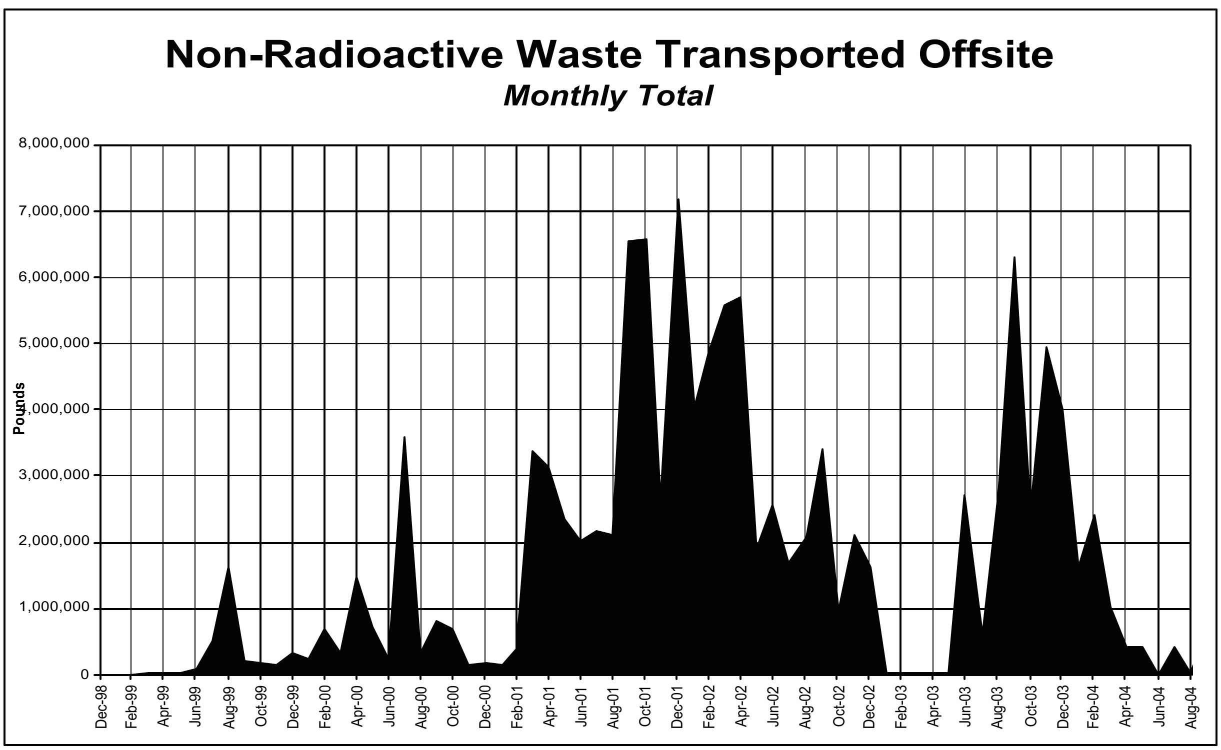

Figure E-2 Maine Yankee Non-radioactive Waste Shipments - Monthly Totals 1998 - 2004

F ADDITIONAL RECOMMENDATIONS FOR OPERATING FACILITIES

The following recommendations are from current Maine Yankee personnel as well as from a speech given by the Maine Yankee Vice President of Decommissioning at a conference in November 2002. They provide Maine Yankee's perspective on recommendations for operating plants based from the decommissioning viewpoint.

Stakeholder Relations

- Invest more energy into building relations with facility opponents
- Invest more energy into engaging in dialogue with the local community (i.e., form an operating community advisory panel
- Cultivate relationships one by one with key stakeholders
- In transitioning into decommissioning, don't underestimate the level of interest and concern among state regulators, the state Governor, and key legislators
- Don't promise or imply that you will necessarily return the site to the way is was before the plant was built
- Consider a CAP type group for operating plants to establish two way communication and build relationships early on

Contamination Control

- Operate a clean plant – prevent leaks and spills, and clean them up quickly when they occur
- Aggressively control contamination and eliminate hot spots
- Maintain stringent and well documented free release control processes
- Minimize the amount of radiation work performed outside the restricted area

Build a Strong Historical Site Assessment (HSA)

- Build your HSA as you operate. Include good records on radiological and non-radiological spills and excavation activities
- Include movement and disposal of soils during plant modifications
- Include a series of site aerial photos and pictures of structures, systems and components over time
- Include spill and event questions in employee out-processing forms

Sampling and Monitoring

- Conduct a ground water monitoring program
- Include hard-to-detect (HTD) analyses when performing nuclide profiles of systems and materials
- Pick a very good laboratory for sample analysis and establish consistent low minimum detectable activities (MDAs) for analytical procedures
- Use EPA guidelines with independent testing for remediation of chemical spills
- Conduct removal and confirmatory sampling in accordance with U.S. NRC, U.S. EPA and state closure and land transfer requirements
- Identify and become familiar with the U.S. EPA and state site closure requirements and real-estate transfer requirements.

Structures and Equipment

- Look at total life cycle including removal and disposal when designing modifications and operating processes
- Integrate utility (water, sewer, telephone, electricity, computers, parking, traffic, shipping, office space and maintenance shops) needs, plans, locations and proposed movement in decommissioning planning
- Thoroughly apply sealant to original construction joints
- Avoid use of underground piping (or place into structured pipe chases)
- Maintain strict controls on solvent and oil use
- Ship waste offsite when generated – avoid legacy wastes
- Construct clear separation between containment and spent fuel pool in fuel transfer tube
- Spent fuel pool crane should be single failure proof
- Eliminate floor drains and buried piping where possible
- Know what is underground

Develop a Good Decommissioning Plan

- Lack of pre-planning can add $50-$100 million to total decommissioning costs
- The earlier the facility end state is established the better
- Transition to a decommissioning mindset as quickly as possible – unneeded or cumbersome operating processes, procedures and oversight can be costly.
- Establish a decommissioning plan including:
  - Assessment of DOC vs. Self-performance
  - Stakeholder involvement program
  - Safety emphasis

    - Schedule importance
    - Well thought out sequence of events
    - Identify business risks including low level waste disposal
- A good plan leads to more confident cost estimating and efficient change to decommissioning even when abrupt changes are needed
- Develop a plan to transition staff from operational to project management structure
- Develop a listing of permits and regulations applicable to decommissioning and plant end state
- Decide what is going to stay following decommissioning (e.g., foundations, discharge piping, infrastructure, etc.)

Other Items

- Avoid being classified as a RCRA large quantity generator
- Maintain a strong document control system including effective retrieval, and prompt disposal of unneeded documents
- Avoid acquiring land with relic dumps
- Make sure the definition of the your site boundaries are clear and known over time
- For facilities with ocean access, define impacts of high and low tide on location of site boundary

STRATEGY FOR THE MANAGEMENT AND DISPOSAL OF USED NUCLEAR FUEL AND HIGH-LEVEL RADIOACTIVE WASTE

JANUARY 2013

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In 2010, I chartered the *Blue Ribbon Commission on America's Nuclear Future* ("BRC" or "Commission") to conduct a comprehensive review and recommend a plan of action for the management and disposal of the nation's used nuclear fuel and high-level radioactive waste, also referred to as the back-end of the nuclear fuel cycle. Representative Lee Hamilton and General Brent Scowcroft, two distinguished individuals with decades of public service and governing experience, co-chaired the Commission and led a panel of leading scientists, nuclear energy experts, industry leaders, and former elected officials.

Nuclear power is an integral part of our "all-of-the-above" energy strategy. It provides twenty percent of our nation's electricity supply, and the Administration is promoting the safe use of nuclear power through support for new nuclear power plants incorporating state-of-the-art passive safety features as well as a cost-shared program providing technical support for licensing new small reactor designs. Nuclear energy is an important contributor to our nation's energy security, and promotes clean-energy jobs. Nuclear energy production also provides important environmental benefits by producing little carbon dioxide or conventional air pollutant emissions.

An unfailing commitment to protect public health and safety, security, and the environment is essential to ensuring that nuclear power remains part of our diversified clean-energy portfolio. As part of that commitment, safe, long-term management and disposal of used nuclear fuel and high-level radioactive waste must remain a national priority.

Beyond sustaining an important domestic energy source, progress on a disposal solution can also support the clean-up of those sites that hosted production of defense nuclear materials during the Cold War, and help advance key national-security and non-proliferation objectives. More than 40 percent of the Navy's surface and submarine combatant fleet, for example, is now nuclear-powered. The used nuclear fuel it generates likewise requires a permanent disposal solution.

Since the end of the Cold War, significant quantities of weapons-capable plutonium and highly enriched uranium have become surplus to our national security needs. Some of these nuclear materials will be modified so they can be used in reactors as fuel, but then will be destined for a repository.

Finally, global demand for nuclear energy continues to grow, with commensurate risks in terms of safety, weapons proliferation, and terrorism if this growth occurs outside a vigorous safety and security framework. America's ability to influence the mitigation of these risks is strengthened when we demonstrate the commitment and ability to perform here at home.

For nearly two years, the Commission conducted a comprehensive review and ultimately made recommendations for addressing one of our nation's most intractable challenges. Its work provides a strong foundation for development of a new strategy to manage used nuclear fuel and high-level radioactive waste. We will work with Congress to build a new national program based on this foundation.

Steven Chu

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INTRODUCTION AND SUMMARY

The *Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste* is a framework for moving toward a sustainable program to deploy an integrated system capable of transporting, storing, and disposing of used nuclear fuel[1] and high-level radioactive waste from civilian nuclear power generation, defense, national security and other activities.

The Strategy addresses several important needs. First, it serves as a statement of Administration policy regarding the importance of addressing the disposition of used nuclear fuel and high-level radioactive waste; it lays out the overall design of a system to address that issue; and it outlines the reforms needed to implement such a system. Second, it presents the Administration's response to the final report and recommendations made by the *Blue Ribbon Commission on America's Nuclear Future* ("BRC"). It also responds to direction in the Joint Explanatory Statement accompanying the Consolidated Appropriations Act, 2012, to develop a strategy for the management of used nuclear fuel and nuclear waste in response to the BRC's recommendations. Third, this strategy represents an initial basis for discussions among the Administration, Congress and other stakeholders on a sustainable path forward for disposal of nuclear waste.

The Administration endorses the key principles that underpin the BRC's recommendations. The BRC's report and recommendations provide a starting point for this Strategy, which translates many of the BRC's principles into an actionable framework within which the Administration and Congress can build a national program for the management and disposal of the nation's used nuclear fuel and high-level radioactive waste.[2] The BRC report and the Strategy build on the body of physical and social science work completed during the prior decades and benefit from the lessons learned not only from our nation's experiences, but also from those of other countries.

This Strategy includes a phased, adaptive, and consent-based approach to siting and implementing a comprehensive management and disposal system. At its core, this Strategy endorses a waste management system containing a pilot interim storage facility; a larger, full-scale interim storage facility; and a geologic repository in a timeframe that demonstrates the federal commitment to addressing the

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[1] The term "used nuclear fuel" as used in the BRC charter and in this document is intended to be synonymous with the term "spent nuclear fuel" as used in the Nuclear Waste Policy Act and the Standard Contracts.

[2] The BRC recommendations are available here and are summarized as follows:

1. A new, consent-based approach to siting future nuclear waste management facilities.
2. A new organization dedicated solely to implementing the waste management program and empowered with the authority and resources to succeed.
3. Access to the funds nuclear utility ratepayers are providing for the purpose of nuclear waste management.
4. Prompt efforts to develop one or more geologic disposal facilities.
5. Prompt efforts to develop one or more consolidated storage facilities.
6. Prompt efforts to prepare for the eventual large-scale transport of used nuclear fuel and high-level waste to consolidated storage and disposal facilities when such facilities become available.
7. Support for continued U.S. innovation in nuclear energy technology and for workforce development.
8. Active U.S. leadership in international efforts to address safety, waste management, non-proliferation, and security concerns.

nuclear waste issue, builds capability to implement a program to meet that commitment, and prioritizes the acceptance of fuel from shut-down reactors. A consent-based siting process could result in more than one storage facility and/or repository, depending on the outcome of discussions with host communities; the Nuclear Waste Policy Act of 1982 (NWPA) envisaged the need for multiple repositories as a matter of equity between regions of the country. As a starting place, this Strategy is focused on just one of each facility.

With the appropriate authorizations from Congress, the Administration currently plans to implement a program over the next 10 years that:

- Sites, designs and licenses, constructs and begins operations of a pilot interim storage facility by 2021 with an initial focus on accepting used nuclear fuel from shut-down reactor sites;
- Advances toward the siting and licensing of a larger interim storage facility to be available by 2025 that will have sufficient capacity to provide flexibility in the waste management system and allows for acceptance of enough used nuclear fuel to reduce expected government liabilities; and
- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048.

Full implementation of this program will require legislation to enable the timely deployment of the system elements noted above. Legislation should also include the requirements for consent-based siting; a reformed funding approach that provides sufficient and timely resources; and the establishment of a new organization to implement the program, the structure of which should balance greater autonomy with the need for continued Executive and Legislative branch oversight. The Administration looks forward to engaging Congress on comprehensive legislation to move forward on this important national responsibility.

In the meantime, the Administration, through the Department of Energy (DOE), is undertaking activities within existing Congressional authorization to plan for the eventual transportation, storage, and disposal of used nuclear fuel. Activities range from examining waste management system design concepts, to developing plans for consent-based siting processes, to conducting research and development on the suitability of various geologies for a repository. These activities are designed to not limit the options of either the Administration or Congress and could be transferred to the new waste management and disposal organization when it is established.

BACKGROUND

The NWPA established a broad policy framework for the permanent disposal of used nuclear fuel and high-level radioactive waste derived from nuclear power generation. The NWPA authorized the government to enter into contracts with reactor operators – the generators and current owners of used nuclear fuel – providing that, in exchange for the payment of fees, the government would assume responsibility for permanent disposal. The fees were to ensure that the reactor owners and power

generators pay the full cost of the disposal of their used nuclear fuel and high-level radioactive waste.

The federal government did not meet its contractual obligation to begin accepting used nuclear fuel by 1998. As a result of litigation by contract holders, the government was found in partial breach of contract, and is now liable for damages to some utilities to cover the costs of on-site, at-reactor storage.

Currently more than 68,000 metric tons heavy metal (MTHM) of used nuclear fuel are stored at 72 commercial power plants around the country with approximately 2,000 MTHM added to that amount every year. The sooner that legislation enables progress on implementing this Strategy, the lower the ultimate cost will be to the taxpayers. This document outlines a strategy that is intended to limit, and then end, liability costs by making it possible for the government to begin performing on its contractual obligations.

The NWPA specified a process for evaluating sites for a repository. The Administration concurs with the conclusion of the BRC that a fundamental flaw of the 1987 amendments to the NWPA was the imposition of a site for characterization, rather than directing a siting process that is, as the BRC recommends, "explicitly adaptive, staged, and consent-based…" In practical terms, this means encouraging communities to volunteer to be considered to host a nuclear waste management facility while also allowing for the waste management organization to approach communities that it believes can meet the siting requirements. Under such an arrangement, communities could volunteer to provide a consolidated interim storage facility and/or a repository in expectation of the economic activity that would result from the siting, construction, and operation of such a facility in their communities.

In addition to commercial used nuclear fuel, high-level radioactive wastes that are the by-products of the production of the nation's nuclear weapons and used fuel from the Navy's nuclear powered combat vessels also require a defined disposal path. These wastes are currently stored at sites in Idaho, South Carolina, and Washington. Also, significant quantities of weapons-capable plutonium and highly enriched uranium have become surplus to our national security needs, and in some form will be destined for disposal in a repository.

STRATEGY ELEMENTS

This Strategy provides a basis for the Administration to work with Congress to design and implement a program to meet the government's obligation to take title to and permanently dispose of used nuclear fuel and high-level radioactive waste. It also provides near-term steps to be implemented by DOE pending enactment of new legislation. The key elements of this Strategy are captured in Figure 1.

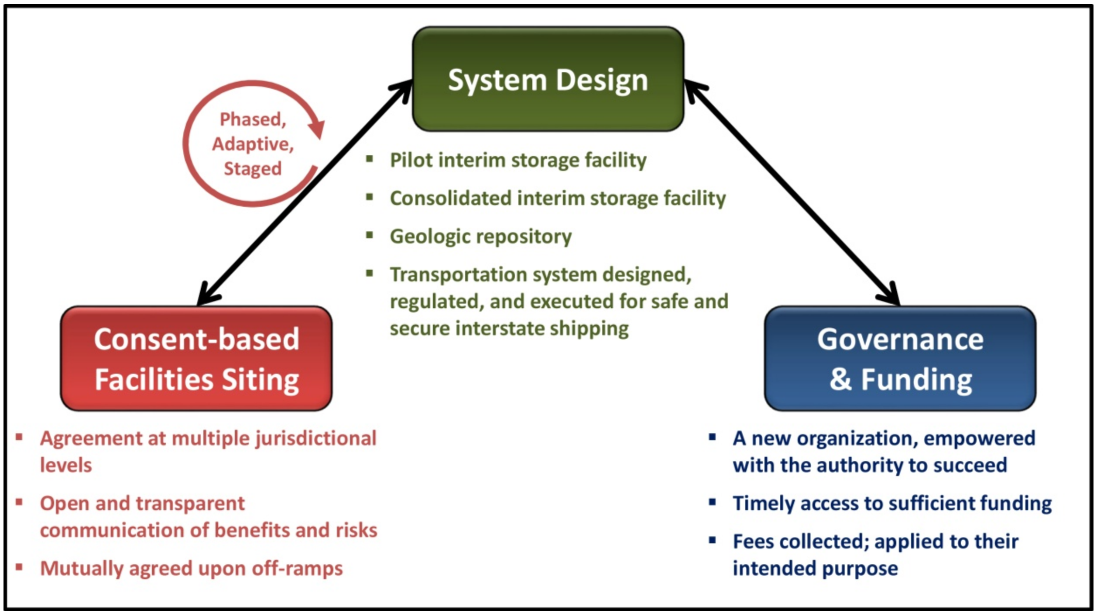


Figure 1. Key Strategy Elements

System Design

The Administration supports an approach to system design that integrates consent-based siting principles and makes progress in demonstrating the federal commitment to addressing used nuclear fuel and high-level radioactive waste disposal, including building the capability to begin executing that commitment within the next 10 years. The Administration supports a nuclear waste management system with the following elements:

- A pilot interim storage facility with limited capacity capable of accepting used nuclear fuel and high-level radioactive waste and initially focused on serving shut-down reactor sites;
- A larger, consolidated interim storage facility, potentially co-located with the pilot facility and/or with a geologic repository, that provides the needed flexibility in the waste management system and allows for important near-term progress in implementing the federal commitment; and
- A permanent geologic repository for the disposal of used nuclear fuel and high-level radioactive waste.

The objective is to implement a flexible waste management system incrementally in order to ensure safe and secure operations, gain trust among stakeholders, and adapt operations based on lessons learned. As will be addressed in the following section on implementation, the Administration agrees with the Blue Ribbon Commission that a consent-based siting process offers the promise of sustainable decisions for both storage and disposal facilities. Figure 2 below portrays a set of possible pathways to developing system facilities and capabilities.

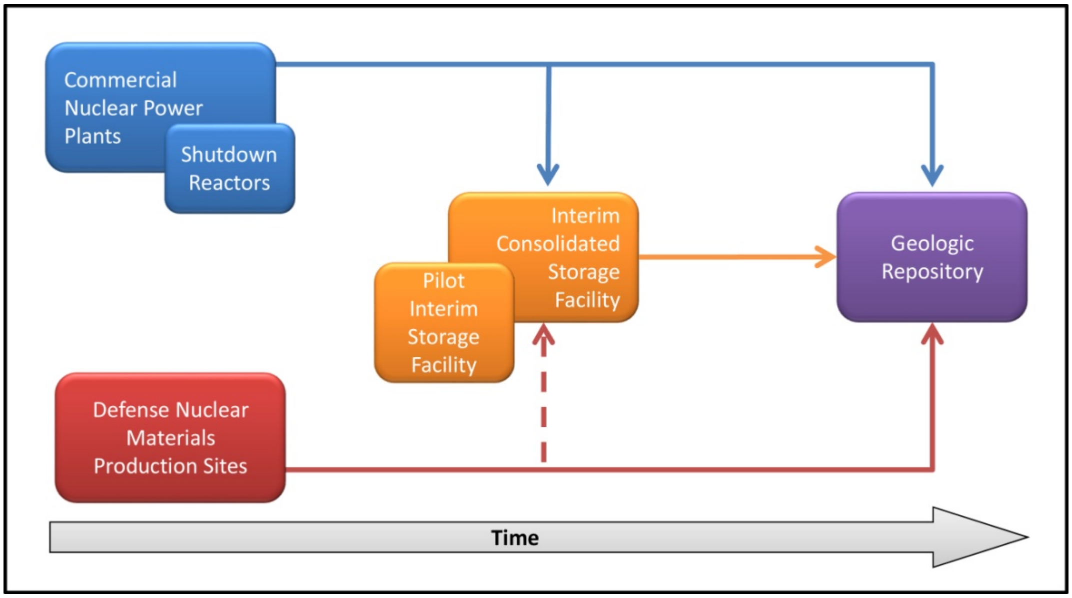


Figure 2. Possible system pathways

This system would initially be focused on acceptance of used nuclear fuel from shut-down reactors; such fuel provides an opportunity to build waste handling capability as well as to relieve surrounding communities and utility contract holders of the burdens associated with long-term storage of used nuclear fuel at a shut-down reactor. Following these initial efforts, capacity will be developed to enable the acceptance and transportation of used nuclear fuel at rates greater than that at which utilities are currently discharging it in order to gradually work off the current inventory. The Administration remains committed to addressing the Cold War legacy; and, in addition to ongoing efforts, will consider transportation and interim storage of government-owned used nuclear fuel and high-level radioactive waste at interim storage facilities.

Interim Storage

The BRC recommended that "one or more consolidated (interim) storage facilities be developed to start the orderly transfer of used nuclear fuel from reactor sites to safe and secure centralized facilities independent of the schedule for operating a permanent repository." The Administration agrees that interim storage should be included as a critical element in the waste management system and has several benefits, including flexibility in system planning and execution and the opportunity to move expeditiously to fulfill government contractual responsibilities.

The Administration also agrees with the BRC that a linkage between opening an interim storage facility and progress toward a repository is important so that states and communities that consent to hosting a consolidated interim storage facility do not face the prospect of a *de facto* permanent facility without consent. However, this linkage should not be such that it overly restricts forward movement on a pilot or larger storage facility that could make progress against the waste management mission. The NWPA currently constrains the development of a storage facility by limiting the start of construction of such a facility until after the Nuclear Regulatory Commission (NRC) has issued a license for construction of a

repository. This restriction has effectively eliminated the possibility of having an interim storage facility as an integral component of a waste management system.

Consistent with legislation recently under consideration in Congress, the Administration supports the development of a pilot interim storage facility with an initial focus on accepting used nuclear fuel from shut-down reactor sites. Acceptance of used nuclear fuel from shut-down reactors provides a unique opportunity to build and demonstrate the capability to safely transport and store used nuclear fuel, and therefore to make progress on demonstrating the federal commitment to addressing the used nuclear fuel issue. A pilot would also build trust among stakeholders with regard to the consent-based siting process and commitments made with a host community for the facility itself, with jurisdictions along transportation routes, and with communities currently hosting at-reactor storage facilities if enabled by appropriate legislation. The Administration would plan to undertake activities necessary to enable the commencement of operations at this facility in 2021, including conducting a consent-based siting process with interested parties, undertaking the requisite analyses associated with siting such a facility, and initiating engineering and design activities as warranted. Full execution of this plan depends on enactment of revised legislative authority.

Beyond a pilot-scale facility, the Administration supports the development of a larger consolidated interim storage facility with greater capacity and capabilities that will provide flexibility in operation of the transportation system and disposal facilities. In addition, a larger-scale facility could take possession of sufficient quantities of used nuclear fuel to make progress on the reduction of long-term financial liabilities. Depending on the outcome of a consent-based process, this facility could have a capacity of 20,000 MTHM or greater, and could be co-located with the pilot facility or the eventual geologic repository. In the context of the overall waste management system, the Administration supports the goal of siting, designing, licensing, constructing and commencing operations at a consolidated interim storage facility by 2025.

In addition to commercial used nuclear fuel, pilot-scale and larger interim storage facilities could provide similar benefits for government-owned and managed used nuclear fuel and high-level radioactive waste, such as demonstration of capability and flexibility in system operations. Therefore, the feasibility of accepting these wastes at interim storage facilities will be considered.

Transportation

The BRC found that existing standards and regulations for the transportation of used nuclear fuel and high-level radioactive waste administered by DOE, NRC, the U.S. Department of Transportation, and state, local, and tribal governments are proven and functioning well. Consistent with the recommendations of the BRC on this issue, the Administration is moving ahead with initial planning for engagement and technical assistance for transportation operations for state and local governments.

As described in the Ongoing Activities section of this document, the Department is proceeding with planning activities for the development of transportation capabilities and storage facilities to facilitate the acceptance of used nuclear fuel at a pilot interim storage facility within the next 10 years and later

at a larger consolidated interim storage facility. The Administration will undertake the transportation planning and acquisition activities necessary to initiate this process with the intent to transfer them to a separate organizational entity if and when it is authorized by Congress and in operation. Outreach and communication, route analysis, and emergency response planning activities consistent with existing NWPA requirements would be conducted during this time. The Administration agrees with the BRC that the relationships and processes built with other federal agencies, state agencies, and local governments to support logistics of shipments to the Waste Isolation Pilot Plant (WIPP) have been successful and the infrastructure and lessons learned from this experience will be utilized moving forward.

Geologic Disposal

There is international consensus that geologic repositories represent the best known method for permanently disposing of used nuclear fuel and high-level radioactive waste, without putting a burden of continued care on future generations. The BRC recommended that the U.S. undertake “an integrated nuclear waste management program that leads to the timely development of one or more permanent deep geologic facilities for the safe disposal of used fuel and high-level nuclear waste.” The Administration agrees that the development of geologic disposal capacity is currently the most cost-effective way of permanently disposing of used nuclear fuel and high-level radioactive waste while minimizing the burden on future generations. As noted by the BRC, the linkage between storage and disposal is critical to maintaining confidence in the overall system. Therefore, efforts on implementing storage capabilities within the next 10 years will be accompanied by actions to engage in a consent-based siting process and begin to conduct preliminary site investigations for a geologic repository. The Administration’s goal is to have a repository sited by 2026; the site characterized, and the repository designed and licensed by 2042; and the repository constructed and its operations started by 2048. Consistent with this effort, the Administration understands the need for the Environmental Protection Agency to develop a set of generic, non-site-specific, repository safety standards to gain public confidence that any future repository will protect public health and the environment. This will be an important early step in any repository siting effort.

The ability to retrieve used nuclear fuel and high-level radioactive waste from a geologic repository for safety purposes or future reuse has been a subject of repository design debate for many years. A recently completed technical review by Oak Ridge National Laboratory found that approximately 98 percent of the total current inventory of commercial used nuclear fuel by mass can proceed to permanent disposal without the need to ensure post-closure recovery for reuse based on consideration of the viability of economic recovery of nuclear materials, research and development (R&D) needs, time frames in which recycling might be deployed, the wide diversity of types of used nuclear fuel from past operations, and possible uses to support national security interests.[3] This assessment does not preclude any decision about future fuel cycle options, but does indicate that retrievability it is not necessary for purposes of future reuse.

[3] J. C. WAGNER et al., Categorization of Used Nuclear Fuel Inventory in Support of a Comprehensive National Nuclear Fuel Cycle Strategy, ORNL/TM-2012/308 (FCRD-FCT-2012-00232), Oak Ridge National Laboratory, Oak Ridge, Tenn., December 2012.

Disposal of defense wastes alongside commercial wastes is the current policy in accordance with the 1985 decision to use a single repository for both commercial and defense wastes. The issue of "commingling" of wastes in a repository will be the subject of analysis moving forward.

Advanced Fuel Cycles

The BRC concluded that "it is premature at this point for the United States to commit irreversibly to any particular fuel cycle as a matter of government policy…" and pointed out that "it is… very likely that disposal will be needed to safely manage at least some portion of the existing commercial [used nuclear fuel] inventory." Even if a closed fuel cycle were to be adopted in the future, permanent geologic disposal will still be required for residual high-level radioactive waste. Cost, nonproliferation, national security, environmental concerns, and technology limitations are some of the concerns that would need to be addressed before any future decision to close the U.S. fuel cycle through the use of recycling would be made. These factors reinforce the likelihood that the once-through fuel cycle will continue at least for the next few decades. Nevertheless, consistent with past practice and the BRC's recommendations, DOE will continue to conduct research on advanced fuel cycles to inform decisions on new technologies that may contribute to meeting the nation's future energy demands while supporting non-proliferation and used nuclear fuel and high-level radioactive waste management objectives.

International Cooperation

International cooperation has been a cornerstone of both U.S. fuel cycle R&D efforts as well as actions to reduce the global proliferation of nuclear materials. Recently, several countries, led by the U.S. and others, have come together to establish frameworks within which multi-national fuel cycle facilities could enable wider access to the benefits of nuclear power while reducing proliferation risks. The BRC recommended that the U.S. develop the capability "to accept used fuel from foreign commercial reactors, in cases where the President would choose to authorize such imports for reasons of U.S. national security." The focus of the present Strategy is on a clear path for the safe and permanent disposal of U.S. used nuclear fuel and high-level radioactive waste; however, the Administration will continue to evaluate the BRC's recommendation and will discuss with Congress the pros and cons of including it in the new waste disposal program.

Implementation

Critical elements for successful implementation of this Strategy include the establishment of a consent-based siting process, a new organization to execute the waste management mission and implementation of a process for long-term, stable funding. The design of both the new organization and the funding source should strike an appropriate balance between independence of the new organization and the need for oversight by Congress and the Executive branch.

Consent-based Siting

The BRC recommends a siting process that is consent-based, transparent, phased, adaptive, standards- and science-based, and governed by legally-binding agreements between the federal government and host jurisdictions. Indeed, promising experiences in other countries indicate that a consent-based process, developed through engagement with states, tribes, local governments, key stakeholders, and the public, offers a greater probability of success than a top down approach to siting. One of the consequences of a consent-based siting process could be the need to have more than one storage facility and/or repository. Multiple communities with differing interests and strengths may propose options leading to system configurations that involve multiple facilities. However, this Strategy focuses on one pilot storage, consolidated interim storage, and repository.

The BRC offered the view that "a good gauge of consent would be the willingness of the host [jurisdictions] to enter into legally binding agreements…that can protect the interests of their citizens." Defining consent, deciding how that consent is codified, and determining whether or how it is ratified by Congress are critical first steps toward siting the storage facilities and repository discussed above. As such, they are among the near-term activities to be undertaken by the Administration in consultation with Congress and others. Legislation recently under consideration by Congress includes requirements for consent at multiple levels, including Congressional ratification. The Department is currently gathering information from the siting of nuclear facilities in the U.S. and elsewhere in order to better understand critical success factors in these efforts and to facilitate the development of a future siting process for a repository and storage facilities.

This Strategy endorses the proposition that prospective host jurisdictions must be recognized as partners. Public trust and confidence is a prerequisite to the success of the overall effort, as is a program that remains stable over many decades; therefore, public perceptions must be addressed regarding the program's ability to transport, store, and dispose of used nuclear fuel and high-level radioactive waste in a manner that is protective of the public's health, safety, and security and protective of the environment.

Management and Disposal Organization

A new waste management and disposal organization (MDO) is needed to provide the stability, focus, and credibility to build public trust and confidence. Managing waste and used fuel is a governmental responsibility and there are multiple possible structures for this new organization. The MDO would be charged with the management and disposal of commercial used nuclear fuel and the associated interface with the utilities. The government will continue to manage its own high-level radioactive waste and used nuclear fuel until it is transferred to an MDO for storage and/or disposal. The BRC recommended the establishment of new, single-purpose organization "to provide the stability, focus, and credibility that are essential to get the waste program back on track." The BRC recommended a specific model in a congressionally-chartered federal corporation. The Administration agrees that a new organizational entity is needed and believes that there are several viable organizational models that can

possess the critical attributes described below.

As part of the development of this Strategy, the Department of Energy commissioned work by the RAND Corporation to examine organizational alternatives for addressing used nuclear fuel and high-level radioactive wastes.[4] RAND assessed lessons learned from the history of the previous DOE organization and analyzed alternative organizational models currently in use both in and out of government. The study's authors concluded that a federal government corporation and an independent government agency are two promising models for a new organization to manage and dispose of used nuclear fuel and high-level radioactive waste, as both models can achieve the critical attributes of accountability, transparent decision-making, autonomy, a public interest mission, and organizational stability. The study also examined the attributes of federally-chartered private corporations and determined that this model is not a good option because obligations to stockholders and the profit motive could result in weakened public accountability and poor political credibility. The RAND study noted that "The success of any future MDO will be driven by many factors and unforeseen circumstances. The organizational form is only one of these factors and perhaps not even the most important one." Rather, of key importance is the flexibility the U.S. government has in crafting a new organization and the specific characteristics with which that organization is endowed.

Whatever form the new organization takes, organizational stability, leadership continuity, oversight and accountability, and public credibility are critical attributes for future success. The Administration will work with Congress to ensure that the MDO authorization provides adequate authority and leadership to execute its mission, with appropriate oversight and controls. Pending enactment of new legislation to establish the MDO, DOE's existing offices retain responsibility to maintain progress in implementing this Strategy. Once the MDO is established, the Administration will carefully evaluate the appropriate activities to be transferred. DOE will take necessary steps to advance the program while taking every precaution to avoid compromising the later ability of the newly established MDO to succeed.

In addition, the mission of the MDO will need to be carefully defined. For example, funding made available to the MDO should be used only for the management and disposal of radioactive waste. While this could include the management and disposal of waste resulting from the processing of defense materials, the MDO itself should not be authorized to perform research on, fund or conduct activities to reprocess or recycle used nuclear fuel. These limitations on the MDO mission are consistent with the recommendations of the BRC.

Funding

With regard to funding, the BRC noted that "…the success of a revitalized nuclear waste management program will depend on making the revenues generated by the nuclear waste fee and the balance in the

[4] *Choosing a New Organization for Management and Disposition of Commercial and Defense High-Level Radioactive Materials*, RAND Corporation, Washington, DC, MG-1230-DOE, 2012. The report is available free for downloading at www.rand.org/pubs/monographs/MG1230.html.

NWF available when needed and in the amounts needed to implement the program." The Administration agrees that providing adequate and timely funding is critical to the success of the nuclear waste mission.

The NWPA established a self-financing mechanism for the nation's commercial nuclear material management system. Congress intended at the time to ensure a stable, ongoing source of funding for the program and also one that would not burden taxpayers. Under the NWPA, the government currently assesses utilities a fee equal to one mill ($0.001) for each kilowatt-hour of electricity sold from nuclear power plants in exchange for agreeing to accept and permanently dispose of utilities' used nuclear fuel. Fees collected total approximately $750 million per year. This fee income is credited to the Nuclear Waste Fund (NWF, or the "Fund"), a fund held in the U.S. Treasury in which monies in excess of appropriations are invested in non-marketable Treasury securities, and the interest earnings are credited to the Fund. The current balance of the Fund is estimated at $28 billion.

Subsequent to passage of the NWPA, a series of broader budgeting acts passed by Congress have had the effect of disconnecting the revenues from the expenditures necessary for a waste disposal solution. All NWF spending is subject to annual appropriations and is required to compete with other priorities within budget caps imposed on all government discretionary spending, while continued collection of the full amount of fees is credited on the mandatory side of the budget as offsetting receipts. As a result, even though the intent of the NWPA was to make the balances of the NWF available when needed to cover the government's cost to dispose of the used nuclear fuel, there is a disconnect that makes access to funding difficult.

Moving forward, the key challenge is to ensure that past and future fee receipts and accrued interest are made available to meet mission requirements in a timely and dependable manner. To achieve this goal, reform of the current funding arrangement is necessary and should consist of the following elements: ongoing discretionary appropriations, access to annual fee collections provided in legislation either through their reclassification from mandatory to discretionary or as a direct mandatory appropriation of the fees, and eventual access to the balance or "corpus" of the NWF.

First, future funding arrangements should include a role for the Appropriations Committees of Congress through ongoing discretionary appropriations, funded within the discretionary spending limits. Ongoing engagement with the Appropriations committees ensures annual oversight and increases the likelihood of a sustained Congressional commitment to the nuclear waste mission. Annual appropriations could be used to fund expenses that are regular and recurring, such as program management costs, including administrative expenses, salaries and benefits, and studies.

Second, access to annual fee collections could support activities such as the development of interim storage facilities, establishment of the transportation system, siting and characterization of a geologic repository, and execution of regulatory development and oversight. This access could be accomplished either through legislative reclassification of fee collections from mandatory to discretionary, or as a direct mandatory appropriation of the fees, or some combination thereof. Legislative reclassification of fee collections from mandatory to discretionary would allow the fees to offset NWF discretionary

appropriations, so that appropriation of the fees no longer would have to compete with other discretionary priorities. Instead, fees would be provided in amounts needed only above the annual appropriations described above and would also be limited by the amount of fee income, as envisioned by the NWPA. This approach could be preferable if additional Appropriator involvement was desired or deemed necessary and regular annual appropriations of that magnitude could be identified.

Alternatively, a direct mandatory appropriation of the annual fees could be coupled with direct access to the corpus of the NWF, as further discussed below. Under this arrangement, spending could be controlled through annual mandatory spending caps set by Congress or by tying funding levels to specific system development milestones in legislation. With continued oversight by the Appropriations Committees, these mandatory spending caps could be adjusted, as deemed necessary and appropriate. Implementation of either or a combination of both of these approaches will require substantial consultation with Authorizing, Budget, and Appropriations Committees of Congress; the Administration is committed to working with Congress to find a mutually agreeable solution to this issue.

Third, regardless of how access to the annual fees is provided, the substantial corpus of the NWF will be needed at an appropriate time in the future, particularly to support the development of a geologic repository. The cost of constructing repository facilities could outstrip the annual fee collections and other discretionary appropriations discussed above. Direct access to the corpus of the NWF through mandatory appropriations could be carefully managed by limiting its use to specific capital expenditures, tied to performance triggers, such as meeting licensing actions and major construction milestones, or subject to hard spending caps.

The cost of the government's growing liability for partial breach of contracts with nuclear utilities is paid from the Judgment Fund of the U.S. Government. While payments are extensively reviewed by DOE, and must be authorized by the Attorney General prior to disbursement by the Department of the Treasury, as mandatory spending they are not subject to Office of Management and Budget or Congressional approval. Past payments are included in full in the budget, but the budget does not reflect full estimates of the future cost of these liabilities and does not fully reflect the potential future cost of continued insufficient action. Future budget projections would be improved by including the full cost of estimated liability payments in the baselines constructed by both CBO and OMB. If the full cost of the estimated liability payments is accurately reflected in the baseline program costs over the life of the project would eventually be offset by reductions in liabilities as the government begins to pick up sufficient waste from commercial sites. As a result, the projected long-term cost of insufficient action surpasses the cost of implementing the program in the short run.

Any new funding structure for this program will need to balance increased funding flexibility and rigorous spending oversight to help assure that the program is implemented in the most cost-effective manner possible, while still holding the MDO accountable to the President and Congress. Further, crafting the MDO funding structure will require a creative and nuanced approach to providing needed funds with involvement by the Administration and all of the appropriate committees of Congress, working together to achieve a viable solution within the current federal budget rules and procedures.

The President's fiscal year 2014 budget will include additional details regarding funding for the program of work described in this Strategy document.

ONGOING ACTIVITIES

Within DOE, the Office of Nuclear Energy's Office of Fuel Cycle Technology has initiated a planning project with the objective of pursuing activities that can be conducted within the constraints of the NWPA and will facilitate the development of an interim storage facility, of a geologic repository, and of the supporting transportation infrastructure. The activities being conducted can be transferred to a new MDO when established and will not constrain its options. This includes initiating planning for a large-scale transportation program; evaluating operational options for consolidated storage and furthering the design of a generic consolidated storage facility. The Department is also developing plans for initiating a consent-based siting process. The Department will continue with these activities and those listed below, within existing Congressional authorization, while the Administration and Congress work together on potential changes to the nuclear waste management program.

The BRC also urged the Department to evaluate options for transportation of used nuclear fuel from shut down reactors. In 2013, DOE is evaluating the inventory, transportation interface, and shipping status of used nuclear fuel at shut-down reactor sites. The Department has established cooperative agreements with state and regional groups and engaged tribal representatives to begin discussions on transportation planning and emergency response training consistent with NWPA Section 180(c). Further, the Department is considering how best to leverage the work of state and regional groups currently engaged in transportation planning and oversight of radioactive waste shipments to WIPP in New Mexico.

In FY 2013, the Department is undertaking disposal-related research and development work in the following areas: an evaluation of whether direct disposal of existing storage containers used at utility sites can be accomplished in various geologic media; an evaluation of various types and design features of back-filled engineered barriers systems and materials; evaluating geologic media for their impacts on waste isolation; evaluating thermal management options for various geologic media; establishing cooperative agreements with international programs; and developing a research and development plan for deep borehole disposal, consistent with BRC recommendations.

CONCLUSION

In this Strategy, the Administration has highlighted agreement with many of the principles of the BRC recommendations and has outlined actions that, with legislative authorization by Congress, can lead to a safe and responsible solution to managing the nation's nuclear waste. Indeed, action by Congress in the form of new authorizing legislation and appropriations is necessary for success of the waste management mission. Specifically, legislation is needed in the near term to permit or address the following activities over the next 10 years:

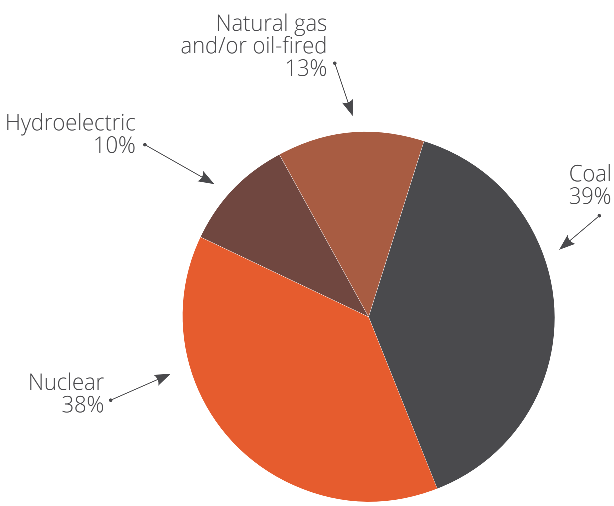
- Active engagement in a broad, national, consent-based process to site pilot and full-scale interim storage facilities, and site and characterize a geologic repository;
- Siting, design, licensing, and commencement of operations at a pilot-scale storage facility with an initial focus on accepting used nuclear fuel from shut-down reactor sites.;
- Significant progress on siting and licensing of a larger consolidated interim storage facility capable of providing system flexibility and an opportunity for more substantial progress in reducing government liabilities;
- Development of transportation capabilities (personnel, processes, equipment) to begin movement of fuel from shut-down reactors;
- Reformation of the funding approach in ways that preserve the necessary role for ongoing discretionary appropriations and also provide additional funds as necessary, whether from reclassified fees or from mandatory appropriation from the NWF or both; and
- Establishment of a new organization to run the program, the structure and positioning of which balance greater autonomy with the need for continued Executive and Legislative branch oversight.

This Strategy translates the BRC's report and recommendations into a set of broad steps that will ultimately benefit the entire nation. The Administration will work closely with Congress to develop a path forward that maximizes the likelihood of success. When executed, the new program will provide near-term and long-term solutions for managing the back-end of the nuclear fuel cycle, thereby resolving a longtime source of conflict in nuclear policy by providing safe, secure, and permanent disposal. Until the necessary new legislation has been enacted, the Administration will pursue components of the Strategy as described above pursuant to current law and in close coordination with Congress. Finally, in executing the program the federal government must work closely with potential host states, tribes, and communities whose engagement will be essential for successfully operating a comprehensive used nuclear fuel and high-level radioactive waste storage, transportation, and disposal system.

Office of the Inspector General
Tennessee Valley Authority
Semiannual Report
April 1, 2015 - September 30, 2015

MAKING TVA BETTER

TVA POWER GENERATION FOR FISCAL YEAR ENDED SEPTEMBER 30, 2015
(in millions of kilowatt hours)



- Coal - 56,017
- Nuclear - 54,543
- Hydroelectric - 13,812
- Natural gas and/or oil-fired - 17,893

*Nonhydro renewable resource is less than 1 percent for the period shown, and therefore not represented on the chart.

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Making TVA Better

MESSAGE FROM

THE INSPECTOR GENERAL

On October 18, 2015, the Tennessee Valley Authority (TVA) Office of the Inspector General (OIG) celebrated its 30th anniversary. In those 30 years, the OIG, like TVA, has evolved. Our office was created as a Board-established office with a Board-appointed Inspector General (IG) during a time when TVA faced a crisis in the building of its nuclear plants. TVA, at the time, had a three-member full-time Board of Directors (Board), received federal appropriations, and employed more than 50,000 people.

Today, the TVA IG, like TVA Board members, is nominated by the President and confirmed by the United States (U.S.) Senate. Other changes over the years include TVA no longer receiving federal appropriations, moving from a full-time three-member Board to a nine-member part-time Board, and reducing its workforce to about 11,000 employees.

Thirty years since our office's inception, TVA is focused on (1) maintaining rates as low as feasible, (2) living within its means, (3) managing its assets to meet reliability expectations and providing a balanced portfolio, (4) being responsible stewards of the region's natural resources, and (5) improving performance and employee engagement.

Throughout these 30 years, the TVA OIG has stayed committed to providing an independent analysis of TVA operations and programs to help identify more efficient and effective ways to do business and to prevent and detect fraud, waste, and abuse. In our feature, "Making TVA Better," we take a look back at our office over the past 30 years, the changes in TVA and TVA OIG, and some of the contributions our office has made to help TVA save or recover money, reduce risks, and improve operations. Making TVA better is a mutual purpose we share with TVA management, employees, and the TVA Board. It is important to the 9 million people of the Tennessee Valley served by TVA that we approach our work with that purpose every day.

The relationship between a federal agency and an IG has been the subject of much comment over the last 30 years. This relationship is arguably one of the most challenging arrangements in the federal government. The natural tensions created by the IG being in the agency but publicly and independently reporting on matters that brings unwanted scrutiny on the agency has proven in TVA's case to be particularly challenging.

For us, this all means that we have to lean forward when it comes to communicating with our stakeholders. In other words, we have found it incumbent on us to initiate dialogue with our stakeholders, including TVA management and the TVA Board, rather than waiting for our stakeholders to ask us questions. We try to explain not just "what" we are doing but also answer the sometimes unspoken question from our stakeholders of "why" we are doing it. Staying in dialogue, despite the fact that there is sometimes disagreement over either the "what" or the "why," requires mutual respect and a united commitment to find a way to work toward our mutual purpose of serving the people of the Tennessee Valley. We appreciate the highly professional working relationship that the OIG enjoys with both the TVA Board and TVA management and their considerable investment in making our relationship productive for all our stakeholders.

With this report, I am pleased to present our work for the period April 1 to September 30, 2015. In this semiannual period, our audit, evaluation, and investigative activities identified more than $12.7 million in funds to be put to better use, questioned costs, recoveries, savings, and penalties, as well as opportunities for TVA to improve its programs and operations. Highlights include:

- A contract compliance audit which questioned more than $7.4 million in rate adjustments and labor costs and associated fees for using rates not included in the contract and a preaward review that identified $2.1 million of potential savings related to overstated labor and burden rates and certain markup rates.

- Organizational effectiveness reviews in TVA's Information Technology (IT) organization which identified improvements made by the groups since previous reviews in 2011, as well as additional areas for improvement going forward.

- An audit of electronic communications by the TVA Board which determined current e-mail practices were consistent with the Presidential and Federal Records Act Amendments of 2014.

- An assessment of TVA's process for developing TVA's 2015 Integrated Resource Plan (IRP) which found the process was adequate in considering potential future uncertainties and associated responses.

- Several reviews that identified improvement opportunities in TVA processes or programs related to invoice approval, talent acquisition and deployment, contractor workforce management, the TVA protocol for handling requests for things of value by certain influential individuals, management of hydro generation obsolete equipment, nuclear outage performance, fire protection, overtime, and executive incentives.

- An investigation that led to a negotiated settlement to repay TVA $1 million because of defective pricing and a rebid of a contract which yielded a savings of $1.8 million.

On a personal note, I want to thank Rob Martin for his many contributions to the TVA OIG. Rob, our Assistant Inspector General for Audits and Evaluations, retired on September 29, 2015, after a distinguished career in government auditing of more than 30 years, including the last 8 years with our office. Rob's leadership and contributions made the OIG and TVA better. We thank you for your service, Rob.

I want to congratulate Dave Wheeler who has been selected as the new Assistant Inspector General for Audits and Evaluations. Dave, who joined our office in March 1987 as an auditor, most recently served as Deputy Assistant Inspector General for Audits. Dave's strong leadership and technical skills position him well to continue the tradition of excellence in Audits and Evaluations.

On July 28, 2015, Director Richard Howorth was nominated for a second term on the TVA Board. Director Howorth has served as the Chair of the People and Performance Committee, Customer and External Relations Committee, and External Relations Committee during his first term. We appreciate Director Howorth's understanding of the role of the OIG and the support he has given our office during his time on the Board. Also, on August 13, 2015, Eric Satz became the newest member of TVA's Board. We welcome Director Satz to the TVA Board and look forward to working with him toward our mutual purpose of making TVA better.

Finally, the TVA OIG lost a friend and supporter with the passing of former Tennessee Senator Fred Thompson on November 1, 2015. At a critical point in the life of the OIG, Senator Thompson stepped up and ushered through the Senate legislation to make the TVA IG a presidentially appointed position. Several years ago I was talking to the Senator and expressing my appreciation for what he had done, but he shrugged it off with typical Thompson humility. TVA is better because of Fred Thompson, and the OIG will cherish his memory.

Richard W. Moore

Richard W. Moore
Inspector General

SPECIAL FEATURE

OIG CELEBRATES 30 YEARS OF MAKING TVA BETTER

On October 18, 2015, the TVA OIG marked 30 years of working to make TVA better. We pause to consider the difference that having an independent OIG has made in TVA history. Whatever value the OIG has added has been possible through a collaborative effort with the TVA Board and with TVA management. In many ways, our reflections on the accomplishments of the OIG over these 30 years are an acknowledgment of the good work done by many. We have been privileged to serve with very dedicated and proficient Board members and TVA employees who have worked alongside of us to make TVA better.

As a corporate body, TVA "wakes up" every morning knowing it has to earn the right to survive. The list of critics questioning the usefulness of TVA continues to grow. TVA has responded by going about the job of "keeping the lights on" in a workman-like fashion that often silences all but the harshest critics. TVA continues to contend with imposing challenges in carrying out its mission. Some of the challenges over the past 30 years included: (1) the shutdown and restart of the nuclear program in the late 1980s, (2) predictable enterprise-wide cost cutting and downsizing over the years, (3) periodic attempts to improve the work environment and culture, (4) the financial and reputational damage caused by the Kingston ash spill, (5) defending attempts to privatize the agency, (6) complying with environmental regulations, and (7) conflicting views about how to manage TVA's debt.

We would like to think that some of what TVA has accomplished over the last 30 years was aided by the OIG. Some of the things TVA can take pride in include: (1) consistently providing reliable power at competitive rates, (2) the restart of Browns Ferry Unit 1, (3) the successful cleanup of the Kingston coal ash spill, (4) successfully expanding the power generation capabilities with combustion turbine generation, (5) reducing the number of aging fossil plants, (6) improving customer relationships, and (7) nearing completion of the first nuclear reactor in the 21st Century at Watts Bar Nuclear Plant (WBN).

This article will provide some background on why OIGs were created and, more specifically the creation of the TVA OIG, and give a brief history of the different periods throughout the OIG history, as well as a summation of what the OIG has been able to accomplish in carrying out the vision of Making TVA Better.

A MATTER OF PUBLIC TRUST

In 1993, Professor Paul C. Light's seminal work, *Inspectors General and the Search for Accountability*, quickly became the authoritative source on the work of IGs. Light traced the origins of the federal IG concept and the sometimes unrealistic expectations placed on IGs to "clean up government." Congress expanded the number and size of the various OIGs in the late 1970s and into the 1980s in response to a series of scandals in federal agencies.

As Paul Light explains, the IG Act of 1978 was designed to do basically four things: consolidate the scattered audit and investigation divisions into an IG office for each federal agency; ensure a measure of independence by putting presidential appointees into the jobs; give the IGs wide latitude in the scope of their work and in how to organize their offices; and provide greater resources for the war on fraud, waste, and abuse.

According to Light, the effectiveness of the IG concept should be measured in terms of the "quality of life produced by the government." Whether a better quality of life was being ushered in by the IGs could be addressed by asking these four questions: (1) Is anyone listening? (2) Is the public more trusting? (3) Is the government less vulnerable to fraud, waste, and abuse? and (4) Is the government producing outcomes of greater public value? Light concluded that at least back in the early 1990s the results were mixed.

With all due respect to Professor Light, those inquiries seem to impute far more power than IGs actually enjoy. IGs should be able to "move the needle" on the metrics that count in government, but much of the final results lie outside the scope of an IG's work. Light recognized that measuring the effectiveness of OIGs is indeed tricky. Raw statistics rarely tell the whole story.

Ultimately, however, Professor Light's conclusion that the work of an OIG should make life better for people seems right. For us, that means our work should improve the quality of life for the residents of the Tennessee Valley. It's a matter of public trust.

THE OIG: BORN IN CONTROVERSY

In the mid-1980s, TVA was grappling with its encumbered nuclear program which led to the shutdown of all its nuclear operating plants, the cancellation of three unfinished plants,

and deferred construction on two other plants. To address these problems, a recommendation to hire a nuclear consultant and an IG was made. There were already 12 OIGs created by the IG Act of 1978. Consequently, there was a pervasive sentiment at the time that if TVA didn't create an OIG, Congress might consider creating one for them. As a result, Board Chairman Charles H. Dean and Director John B. Waters approved the OIG's creation stating there was a need to have an independent organization within TVA to receive complaints that reported directly to the Board and to Congress.

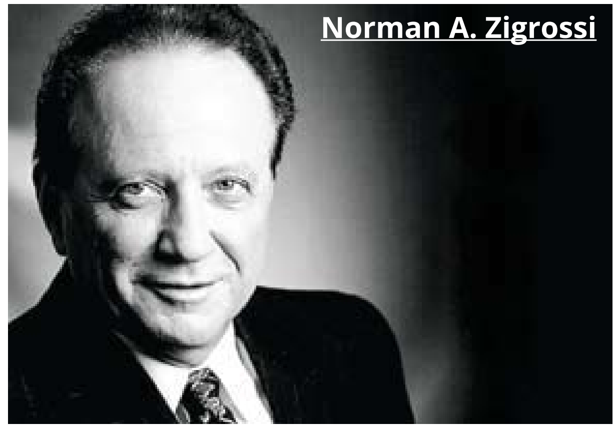
While the three-person Board approved the creation of the OIG with a vote of 2 to 0, one Board member, David Freeman, removed himself from the voting process. Mr. Freeman did not want to hinder progress in hiring an IG, but did not think an IG was a fit for a business like TVA. TVA employees were also divided on the decision to hire an IG.

Despite its controversy, the TVA OIG was created with the following parameters outlined in the Board's plan: The IG will be independent of TVA management, with a separate staff and budget, and will report directly to the Board. He or she can be removed from office only by the Board, which must justify the action to Congress. The IG will have access to all TVA records and can make "any investigation deemed necessary or desirable by the inspector general." To maintain employee confidentiality, "the Board intends for the IG to receive in confidence allegations about any aspect of TVA."

Former TVA General Manager Bill Willis began compiling a list of names for consideration to fill the role of the IG, who would be named on December 1, 1985.

First Inspector General Norman A. Zigrossi, 1986 - 1992

Norm Zigrossi, prior to becoming TVA's first IG, worked for the Federal Bureau of Investigation (FBI) for 23 years, including serving as the Special Agent in Charge of the FBI's Washington, D.C., and San Diego, California, field offices. Mr. Zigrossi reported for duty in January 1986 as TVA



continued to shut down its nuclear plants to address safety concerns. The basic problem with the nuclear program was soon recognized as a lack of effective management systems throughout the program. This would ultimately provide much of the basis for TVA OIG's initial caseload.

One of the first challenges facing the OIG involved nuclear-related employee concerns. TVA contracted with a company to investigate the issues in its nuclear program which resulted in more than 6,000 interviews of TVA employees and more than 5,000 concerns identified through those interviews. When TVA terminated its contract with that company, the concerns were transferred to the Nuclear Regulatory Commission (NRC) and the majority of the issues were ultimately turned over to the OIG, resulting in opening 605 investigations.

Shortly after the creation of TVA's OIG, President Ronald W. Reagan appointed Marvin T. Runyon the ninth chairman of the TVA Board. Mr. Runyon had previously served in executive roles at Ford Motor Company and Nissan, where he and other leaders attempted to boost morale, build a strong culture, and focus on quality.[1] When Mr. Runyon stepped into his position at TVA, he ". . . found an agency that was badly dated in its operations and practically crippled by a failed attempt to develop nuclear power."[2] Further, TVA had invested $5 billion in the construction of three nuclear plants which were subsequently cancelled. Each of these events had serious negative impacts on TVA's public perception of TVA, customer and employee relationships, and operations.

[1] R. Earl Thomas and Neil E. Watson, *Marvin Runyon: A Commitment to Excellence*, <http://www.anbhf.org/pdf/runyon.pdf>, accessed on May 5, 2013.
[2] Fred S. Rolater, Marvin Runyon, Middle Tennessee State University, February 24, 2011.

To be able to continue as a viable organization, TVA needed to fundamentally change the way it conducted its business. Soon after beginning at TVA, Mr. Runyon determined that organizations were not aligned. Various groups within TVA were not cohesively working together toward one mission but were marching off in separate directions. Mr. Runyon outlined steps for change, such as reexamining TVA's purpose and establishing a clear plan for the future; restoring TVA's nuclear program; and improving leadership, teamwork, and communication within TVA. Mr. Runyon hoped these changes would result in "... greater responsibility and accountability in moving decision making to the lowest operating levels possible."[3] TVA staffing levels at the height of construction was nearing 50,000 employees. Mr. Runyon began efforts to significantly reduce the size of TVA's workforce.

Also, in 1988, TVA froze wholesale rates, primarily due to dramatic rate increases during the previous two decades and eroding public confidence. The rate freeze would continue for 10 years until 1997. While the rate freeze may have improved TVA's relations with its customers and residents of the Tennessee Valley in the short-term, it also increased TVA's financial pressures later.

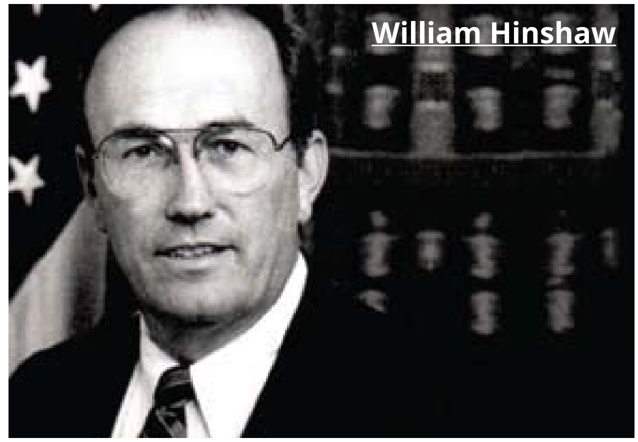
During these challenging times at TVA, the OIG focused significant attention on investigating the nuclear-related employee concerns and identifying opportunities to achieve savings and cost reductions. One such opportunity was establishment of the contract preaward program which helped identify potential cost savings. Significant results from OIG audits also included the avoidance of a significant rate increase to customers as a result of a recommendation by the OIG to initiate a change in accounting policy. In addition, a number of program areas were identified where opportunities existed to improve effectiveness and achieve higher results.

1986 TVA OIG Group Photo

[3] Roger L. Cole and Larry A. Pace, *Power to Change: The Case of TVA*, Training and Development, August 1991, p. 60.

Additionally, Mr. Zigrossi quickly established a hotline—known today as the EmPowerline (1-855-882-8585)—for TVA employees, contractor employees, or members of the public to anonymously or confidentially report any suspected waste, fraud, or abuse potentially affecting TVA.

On October 18, 1988, President Reagan signed into law Public Law No. 100-504, IG Act Amendments, establishing the TVA OIG and 32 others as statutory IG offices. This law made the OIG responsible for TVA's audit and investigative activities.



Second Inspector General William L. Hinshaw II, 1992 - 1994

When Mr. Zigrossi resigned to become a TVA manager, William L. Hinshaw II, a 24-year veteran of the FBI, assumed the TVA IG role on May 1, 1992.

Mr. Hinshaw focused on initially establishing a greater OIG presence in the Valley as TVA operations and personnel were scattered throughout the region. So, in 1992, he directed the opening of satellite offices—first in Chattanooga, Tennessee, and Huntsville, Alabama, and then, in Memphis, Tennessee. Mr. Hinshaw was also focused on making the OIG more efficient and effective in the delivery of the OIG mission. Some of these actions included the formation of Quality Action Teams to address, among other things, OIG employees' issues and concerns about their career paths, performance appraisals, and employee development.

In 1993, he created an Inspections unit utilizing staff from Audits and Investigations. The intent of the Inspections team was to foster innovative approaches that were responsive to management's needs and provide timely services to enable management to promote economy, effectiveness, and efficiency within their own programs. The approach was designed to build constructive relationships with TVA management, assuring them that the OIG's primary goal was to effect positive change rather than finding fault for noncompliance with existing rules and regulations.
TVA's challenges were evolving. In the 1990s, legislative action drove TVA's renewed focus on becoming more competitive in the utility industry. The Energy Policy Act of 1992 appeared to be paving the way for requiring utilities to wheel power from one another. Wheeling power would involve TVA transmitting power generated by another utility using TVA transmission lines while the customer pays the generating utility, not TVA, for the power. TVA was exempted from the Energy Policy Act of 1992 for power sold and consumed within the TVA "fence." However, there was legislative movement towards eliminating the TVA exemption, thus making TVA subject to wheeling power and introducing competition into the "fence." Additionally, neighboring private utilities, concerned that TVA's position as a federal utility would provide an unfair advantage in a deregulated marketplace, organized a lobbying group called TVA Watch. In 1995, TVA commissioned a report called "The Ties That Bind" which assessed the ". . . financial status, generating capacity and likely competitors within the region, and concluded that the "fence should come down." Intended to emphasize TVA's self-supporting nature, the report was viewed by TVA Watch as a preemptive strike indicating TVA planned to target other utilities' customer bases. Deregulation was expected to become reality and would plunge TVA into a competitive environment. Even if deregulation did not come to fruition immediately, TVA saw the need to become more competitive.

Significant OIG reviews during this time included a joint audit and investigation that resulted in $8.37 million recovery from TVA's medical plan administrator, $10 million in questioned costs related to price adjustment claims, and a review of the technology brokering program. The technology brokering program review resulted in Mr. Hinshaw testifying before Congress on TVA's role

in using cooperative agreements for procurement of unauthorized services for the U.S. Department of Defense.

Third Inspector General George T. Prosser, 1994 - 2000

On April 1, 1994, George T. Prosser became TVA's third IG and the first OIG employee to become the IG after having served in the office as the Assistant Inspector General, Investigations (AIGI) and as the Manager of Fraud Investigations. Prior to his roles in the TVA OIG, Mr. Prosser was a 15-year veteran of the FBI—serving as a supervisory special agent in the Terrorism Section at FBI Headquarters and as the Senior Special Agent in the FBI's Chattanooga resident agency. While serving as the AIGI, Mr. Prosser's efforts in detecting fraud and abuse in TVA's workers' compensation program received a public service award from the President's Council on Integrity and Efficiency (PCIE)—an IG community group.

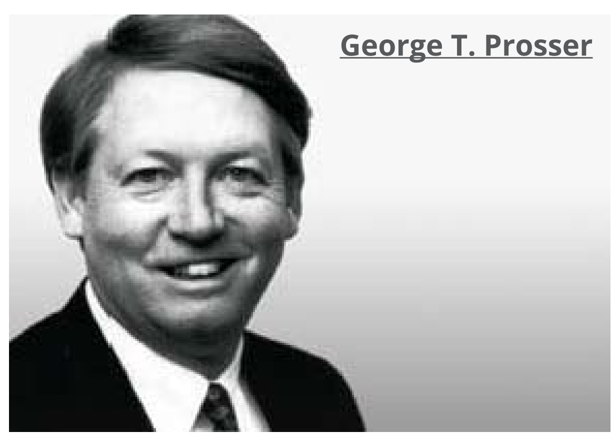
During the mid to late 1990's, TVA continued to deal with the challenges and controversies related to becoming more competitive in a deregulated market. As deregulation was being discussed, Enron began operations of some of its gas-fired combustion turbine plants located within the TVA fence. Additionally, the decade-long rate freeze that began in 1988 improved relations with TVA customers in the short-term, but it also resulted in unforeseen consequences. Presumably, the loss of potential revenue associated with the 10-year rate freeze placed pressure on TVA to cause it to increase its debt borrowing, resulting in high financing costs. The Office of Management and Budget began pressuring TVA to pay back existing debt and limit the growth of debt, at a time when environmental regulations were increasing in complexity and adding additional costs. In July 1997, TVA issued a 10-year-business plan. The plan attempted "... to position TVA to be more competitive by, among other things, reducing its high debt servicing and other fixed costs." The ultimate objective of the plan was to offer competitively priced power and reduce debt by about one-half (to approximately $14 billion) by 2007. This plan proved to be unrealistic due to a number of factors including the U.S. Environmental Protection Agency requirements pursuant to the Clean Air Act to retrofit the fossil plants with expensive emissions control equipment.

Finally, internally, TVA faced a projected high attrition rate and loss of long-term employees and their knowledge. Change was on the horizon, and TVA needed a navigation plan for the future.

During this time, Congressional concerns arose related to a number of TVA management practices, including advertising, sole-source contracting, special events and entertainment, use of TVA airplanes, and other management practices. Congressman Zach Wamp engaged the OIG to review and provide greater oversight in all of these areas. Other challenges during this time included the indictment of the Chief Operating Officer who was later acquitted and controversy around the creation of the Center for Rural Studies which was established by TVA and funded with a $30 million irrevocable trust. TVA subsequently revoked the funding and dissolved the organization.

During Mr. Prosser's time as IG, the TVA OIG worked on some impactful projects that significantly benefitted TVA. Some of the more significant projects included the following:

- In 1994, the OIG completed a comprehensive Concerns Resolution Staff program review. Then, in 1995, TVA Nuclear management asked the OIG to review the program at WBN due to the NRC's interest in the program. In both cases, the OIG's findings were generally positive. That September, an OIG special project team briefed senior NRC officials in Washington, D.C., on the results of the review. These reviews have continued through the ensuing years.



- During 1993 and 1994, the OIG participated in the "Federal Employees Compensation Act (FECA) Fraud Deterrence Group," which was selected to receive the Secretary of Labor's Exceptional Achievement Award for 1995. The group played a significant role in the enactment of Public Law 103-329, which bans payment of FECA benefits to claimants who are convicted of defrauding the program, suspends payment of benefits to incarcerated felons, and changes the FECA fraud statute from a misdemeanor to a felony.

- In 1997, special agents from the OIG became part of a newly formed federal and state Environmental Crimes Joint Task Force. This joining of forces soon bore fruit with three convictions in 1998. The work of the task force has continued through the years resulting in many more convictions for environmental crimes affecting TVA waterways and land.

- With year 2000 approaching, 1997 was the year the OIG began to review TVA's year 2000 computer rollover activities, the success of which was critical to prevent disruption in the delivery of electric power. Any type of system failure could have resulted in anything from small customer inconvenience to electric power plant shutdown, affecting millions of customers. OIG reviews helped to assure the smooth transition to the 21st Century.

In 1999, a major event occurred that called into question whether the former TVA Board Chairman was trying to impede the independence of the IG, which was a TVA Board-appointed position. U.S. General Accounting Office, now known as the Government Accountability Office (GAO), investigated allegations against the former TVA Board Chairman as well as allegations the Chairman made against the IG related to misuse of a TVA credit card. GAO[4] found (1) the Chairman's actions "…could be viewed as an attempt to undermine the independence of the IG" and (2) "… no evidence of TVA credit card misuse by the IG." As a result of this event, the late Senator Fred Thompson sponsored a bill to make the TVA IG a presidential appointment which Congress later enacted into law.

Mr. Prosser stepped aside as IG effective August 14, 2000, though he remained as an advisor to the new IG for several months. On September 14, 2000, an IG community group called the Executive Council on Integrity and Efficiency (ECIE) honored Mr. Prosser for outstanding contributions to the IG community.

Fourth Inspector General Richard F. Chambers, 2000 - 2002

Effective August 14, 2000, Richard F. Chambers became the fourth TVA IG. Mr. Chambers previously was at the U.S. Postal Service OIG, where he served as Assistant Inspector General of Audits and then Deputy IG. Prior to the Postal Service, Mr. Chambers worked for more than 20 years in positions of increasing audit and management responsibility, primarily with the U.S. Army, including as Director U.S. Army Internal Review and Chief, Internal Review and Audit Compliance, U.S. Forces Command.

During Mr. Chambers' term, a number of Congressional concerns were raised. TVA OIG responded to several requests from congressmen to review aspects of interest in TVA operations.

- At Congressman Zach Wamp's request, the OIG performed an updated review of TVA management practices in five areas: consulting contracts, advertising, special events—including barge events, executive air transportation, and the relocation of personnel and programs to Nashville, Tennessee.


Richard F. Chambers

[4] U.S. General Accounting Office, Tennessee Valley Authority: Facts Surrounding Allegations Raised Against the Chairman and the IG, September 15, 1999 http://www.gao.gov/products/OSI-99-20.

- At the request of Senator Mitch McConnell, the OIG reviewed selected issues related to TVA's power rates and costs.

- At the request of Senator Jeff Sessions, the OIG assessed the reasonableness of TVA's decision to consolidate operations in Nashville in the Highland Ridge Tower (HRT) and build-out costs incurred by TVA. The OIG found TVA's decision to select HRT was not the least costly alternative, and TVA incurred some costs associated with the HRT build-out which were unnecessary or unreasonable.

Internally, Mr. Chambers created a separate IT Audit group to focus on cyber security and other IT-related risks, established a computer forensics lab, and focused on staff development.

Shortly after Mr. Chambers took the reigns as TVA IG, on November 1, 2000, President Bill Clinton signed Public Law 106-422, designating the position of TVA IG as presidentially appointed. Mr. Chambers retired from federal service on January 25, 2002. Pursuant to the Federal Vacancies Reform Act, the First Assistant to the IG, G. Donald Hickman, assumed the role of Acting IG.

Acting Inspector General G. Donald Hickman, 2002 - 2003

Subsequent to the tragic events of September 11, 2001, a major effort of the OIG was the initiation of a number of reviews to validate the effectiveness of TVA's security procedures and controls. These efforts were concluded under the direction of Acting IG Hickman.

The initial effort was a preliminary survey to assess the adequacy of TVA's security plans and actions taken in response to the terrorist attacks and related threats. The OIG found that TVA was taking or had taken appropriate measures to mitigate the risks associated with the security of TVA's nuclear and nonnuclear facilities. The OIG also made a major commitment to assist TVA management in developing a cost-effective plan to evaluate TVA computer security procedures and controls.

Donald Hickman

A considerable amount of legislation had been passed requiring federal agencies to review and improve security of its information, e.g., Federal Information Security Management Act (FISMA), and to report annually on its action plans for improvements. The same also requires OIGs to independently evaluate and report on agency compliance. A group of TVA OIG employees became part of an IT Security Assessment project team and by March 31, 2003, the team had conducted 23 self-assessments and 2 vulnerability assessments of TVA information security measures.

In 2002, an OIG audit team was given an Award of Excellence by the PCIE for the team's work in the area of TVA Long-Term Bulk Power Trading. The team produced two highly complex reviews of TVA's weekly, monthly, seasonal, annual, and multiyear trading in the wholesale electricity market. The reviews were especially timely, as several power marketers had either filed for or were on the brink of bankruptcy. In addition, Enron and other utilities were facing scrutiny due to questionable energy trading and practices.

The year 2002 saw the passage of the Homeland Security Act. Section 812 of the Act provided for law enforcement authority for TVA special agents under guidelines to be issued by the U.S. Department of Justice. To ensure a smooth transition, the OIG initiated and developed an intensive law enforcement skills refresher training program. In addition, the OIG began participating on the Joint Terrorism Task Force led by the FBI's Knoxville Field Division.

Additionally, in 2002, the Sarbanes-Oxley Act was enacted in response to the collapse of Wall Street giant Enron and other corporate failures and malfeasance. The Act was intended to protect investors by, among other things, requiring companies to make new disclosures on internal controls, ethics codes, and the makeup of their audit committees. Although the Act did not apply to TVA, TVA began a program to review controls and build the framework that would allow TVA to voluntarily comply, where possible with its provisions. In support of TVA, the OIG performed reviews to help assess TVA's controls over financial reporting. Finally, the OIG assumed budget responsibility for TVA's contract for external audit services and became the technical contract manager for the contract.

On April 22, 2003, President George W. Bush announced his intention to nominate Richard W. Moore to be the next TVA IG. Mr. Hickman returned to his position as the AIGI after confirmation by the U.S. Senate of Mr. Moore.

Fifth Inspector General and First Presidentially Appointed Richard W. Moore, 2003 - Present

Effective May 9, 2003, Richard W. Moore became TVA's first presidentially appointed IG. Prior to becoming the IG, Mr. Moore was an Assistant U.S. Attorney in the southern district of Alabama where he was Chief of the Criminal Division and the Senior Litigation Counsel for the U.S. Attorney's Office. After September 11, 2001, he also served as the Anti-Terrorism Task Force Coordinator. He was an Atlantic Fellow in Public Policy at Oxford University, Oxford, England, while still serving in the U.S. Justice Department.


Richard W. Moore

In the dozen-plus years Mr. Moore has served as TVA's IG, his primary initiatives can be characterized by: (1) a focus on risk-based audits and investigations that produce positive change for TVA, (2) building trust with stakeholders, and (3) investing in a sustainable culture of innovation and continuous improvement for the OIG team.

Risk-Based Audits, Evaluations, and Investigations

The test for an OIG is whether its audits, evaluations, and investigations reduce the level of risks for a federal agency that could otherwise impede the accomplishment of the agency's mission. That starts with an assessment of the effectiveness of the Enterprise Risk Management (ERM) of TVA. The OIG, through its audits, evaluations, and investigations, has encouraged TVA to develop a more robust enterprise risk program.

TVA's ERM program has evolved over the years. In 1999, the OIG recommended TVA establish an ERM program and create a Chief Risk Officer position. Since then, the OIG has reviewed the program in 2003, 2008, and most recently, 2014. In 2008, the OIG review found the program needed to be driven further down into the organization. Three months later, the Kingston ash spill also demonstrated this same need. The Kingston disaster serves as an example of the importance of a properly designed ERM program supported by a healthy culture. The OIG report on Kingston pointed to significant risks that were associated with ash management and known internally as early as 1987, but that information was not captured in any risk matrix. The 2014 review found TVA had significantly improved its ERM program; however, several areas for improvement were identified based on best practices that if not addressed could prevent TVA from having a sustainable, viable, and effective ERM program.

During Mr. Moore's tenure, TVA has faced many challenges and continues to evolve both organizationally and culturally. The OIG has noted many areas where significant program improvement were warranted and made recommendations for improvement over the years. These areas have included supply chain, IT management, cyber security, capital project

management, organizational effectiveness, and various other major programs within TVA.

Information Technology and Supply Chain

In some instances the OIG's work has resulted in major program changes including the discontinuation of some programs. In other situations, the OIG continues to work with the organizations in ever changing conditions that result from technology advancements, organizational restructuring, and changes in leadership and management processes and controls. For example, the OIG has a continuous presence in the areas of supply chain and IT (including cyber security). The OIG has developed a trusting working relationship with these organizations while providing ongoing reviews and assistance in areas such as contract preaward and compliance reviews, process improvement reviews, and assurance that systems are operating as intended.

- In the area of supply chain, our compliance audits and preaward reviews have on average resulted in the identification of about $30 million in annual questioned costs and funds to be put to better use. Additionally, many program improvement recommendations have been made including increased emphasis on employee training and development, quality assurance, and data analysis in supply chain areas of (1) contract administration, (2) contract awards, and (3) invoice review and approvals. While progress has been made, the OIG work continues as TVA restructuring and staff reductions continue to present risks to the Supply Chain organization's progress.

- In the area of IT and cyber security, the OIG maintains a continuous presence because of the ever-changing technology that constantly increases the risk of cyber-attacks and regulatory landscape that increases the risk of fines and penalties due to noncompliance. A main focus of the OIG has been to provide some level of assurance testing around the critical infrastructure of TVA assets as well as the protection of personal data of employees and contractors to ensure these systems and data are being adequately protected. Another focus area has been the overall effectiveness of the IT organization and the effectiveness of their programs. The OIG has performed substantial reviews of the overall IT organizational effectiveness at three different points in time: 2008, 2011, and 2015. While more recent audit results have shown significant improvement, ever-evolving technology, major personnel changes, and other technological challenges continue to pose a level of risk that requires the attention of both TVA management and the OIG. Although the issues are daunting, TVA management has demonstrated a commitment to make the necessary changes.

IGs Norm Zigrossi, Donald Hickman, Richard Moore, William Hinshaw and George Prosser

Collaboration with TVA on Fraud Risk Assessments

In 2004, the OIG began conducting fraud risk assessments throughout TVA, i.e., a process for business process owners to identify and analyze fraud risk factors that may be common to general business practices and also specific to the organization and its operations. With the strong support of TVA management, the fraud risk assessment process has been successful in identifying potential risk areas and mitigation strategies for a number of TVA organizations.

Working collaboratively with TVA management, the OIG assisted them in identifying a number of areas where controls could be improved. TVA management subsequently developed remediation plans for those areas.

As noted previously, the OIG has focused on many significant challenges TVA has faced over the years. Discussed below are some highlights of the OIG work during Mr. Moore's tenure where significant problem areas were identified and recommendations for improvement were made.

- ### *Kinder Morgan Case Results in a $25 Million Settlement*

  A joint investigation and audit team investigated whether TVA was defrauded by three Kinder Morgan limited partnerships (collectively "Kinder Morgan") that provided coal and other energy transportation and distribution services at two coal terminals. The OIG received a tip about how Kinder Morgan was cheating TVA. In this case, TVA and other customers' coal was shipped by rail to terminals, where it was offloaded, stored, and eventually loaded onto barges for delivery. Kinder Morgan used two different weighing methods to show it was shipping out the same amount of coal as it had received. Kinder Morgan claimed the "excess" coal, therefore, belonged to it and it had the right to sell the coal and keep the profit. TVA's usual fly-over precautions did not detect the fraud. The OIG investigation led to a 2007 civil settlement in excess of $25 million.

- ### *Contractor Lies About the Number of Injuries on TVA Nuclear Sites*

  In 2009, TVA contractor Stone & Webster Construction, Inc. (SWCI), agreed to pay $6.2 million to resolve a contract fraud investigation. SWCI, one of TVA's largest contractors during the period under review, was providing maintenance and modification work at TVA's nuclear power plants. SWCI records understated the number and severity of work-related injuries during the years 2004 through 2006. SWCI presented false or fraudulent claims to TVA for reimbursement for certain performance fee bonuses SWCI claimed for meeting safety goals at the three TVA nuclear plants located in Alabama and Tennessee, totaling nearly $3.1 million. The settlement provided that SWCI would pay the U.S. $6.2 million, the equivalent of double damages. In addition to the $6.2 million payment, SWCI entered into a comprehensive two-year Corporate Integrity and Monitoring Agreement with the OIG to ensure that SWCI implements a Compliance and Ethics Program applicable to all work or service provided to TVA and that SWCI fully complied with TVA's policies and directives related to its contracts. This was the first Corporate Integrity and Monitoring Agreement in TVA history between the OIG and a TVA contractor.

- ### *Review of TVA's Maintain and Gain Lakeshore Management Program*

  In August 2008, numerous newspaper articles questioned the fairness of a TVA Maintain and Gain transaction granting water access to The Cove at Blackberry Ridge, LLC (Blackberry)—a 4,200-acre water-lined resort development. Blackberry's primary investor was a congressman who served on the U.S. House Transportation Committee's Subcommittee on Water Resources and the Environment. This Subcommittee provided formal oversight over TVA. TVA's Maintain and Gain Lakeshore Management Program was designed to allow consideration of proposals to obtain lake access rights at the landowner's property by swapping access rights already available at other properties the landowner possessed. Questions were raised about whether the congressman used his position to influence TVA's decision to grant Blackberry's request for water access. Because

doubt was cast on the fairness of a TVA process, the TVA OIG conducted an inspection. We found no evidence of pressure on TVA from the congressman to give Blackberry water access on this lakefront project.

As a result of that inspection, TVA and TVA's Board agreed to develop a policy to provide a means to identify the potential of actual or apparent conflicts of interest or the appearance of the exertion of undue influence on the part of a person applying for a TVA benefit. TVA developed the "Obtaining Things of Value from TVA Protocol" to ensure that when something of value is being sought from TVA, the decision-making process is "fair, impartial, transparent, and evenhanded, both in fact and in appearance."

- ***Kingston Ash Spill Reviews***

In 2009, TVA was continuing to deal with the financial consequences brought about by the December 2008 Kingston ash spill as it cleaned and restored the community to its pre-spill state. That year, the OIG issued two significant reports in regard to the cause of the spill and how TVA was responding to the cleanup.

- An initial OIG review of TVA's response to the Kingston ash spill found: (1) TVA had not properly implemented the National Incident Management System, which hampered communications and delayed certain emergency response actions following the spill; (2) TVA's quick response to the media and public inquiry resulted in the release of inaccurate and inconsistent information, which resulted in criticism of TVA and caused reputational harm to the company; and (3) while TVA responded effectively to victims affected, failure to timely communicate TVA's claims policy and decisions increased settlement expectations for some.

- Our second review of the Kingston ash spill focused on a root cause study performed by a firm contracted by TVA for that purpose. The contract with TVA's expert restricted him from examining TVA's management of coal ash. We found: (1) the root cause analysis was handled by TVA in a manner that avoided full transparency and accountability and was done to preserve TVA's litigation strategy; (2) TVA was aware of "red flags" raised over a long period that signaled the need for safety modifications to the ash ponds which, if addressed, could possibly have prevented the spill; (3) factors other than a faulty "slimes" layer identified by TVA's expert as the trigger for the spill may have been of equal or greater significance; (4) despite internal knowledge of risks associated with the ash ponds and discussions of placing the ponds under TVA's Dam Safety Program, thereby subjecting the ponds to more rigorous


2013 TVA OIG Group Photo

inspections and engineering, TVA's risk management program failed to identify ash management as a risk; and (5) attitudes and conditions that emanated from a legacy culture resulted in ash being relegated to the status of garbage at a landfill rather than treated as a potential hazard to the public and the environment. TVA management generally agreed with OIG recommendations to address these findings.

- ***First Debarment in TVA History***

An OIG investigation found that a TVA technical contract manager received money from a TVA contractor. Criminal proceedings were taken against the former TVA technical contract manager. In addition, a report of administrative inquiry was issued to TVA management regarding the actions of the contractor, Holtec International, Inc.,(Holtec) a company that supplied casks for spent nuclear fuel.

In response to the report, TVA created the position of Suspension and Debarment Officer. Based on the OIG investigation, TVA's Suspension and Debarment Officer issued the first debarment action in TVA history. Holtec received a 60-day debarment in 2010 and agreed to pay a $2 million administrative fee to TVA. Holtec was also required to appoint a Corporate Governance Officer and an independent monitor (at the contractor's expense) to gauge what progress in business ethics the company was making, if any.

- ***Review of WBN Unit 2 - Cost and Schedule***

In August 2007, the TVA Board approved the completion of WBN Unit 2, at a cost of $2.5 billion to be completed in 60 months. The TVA OIG, through joint audits and investigations, determined TVA's WBN construction was significantly behind schedule and grossly over budget, despite information released by TVA senior management to the contrary. We reported that employees and contractors who knew the information being sent to the Chief Executive Officer and to the Board was erroneous were silenced by TVA executives at WBN.

Perhaps equally critical to the resolution of the WBN problem was whether TVA would take responsibility for what had happened. The OIG was in constant dialogue with TVA officials about what TVA would say publicly about the reason that the costs for the project would be so much higher and it would take so much longer to complete the project. The Kingston experience had demonstrated how a public institution can lose the trust of its stakeholders by not being transparent about a significant event. Whether TVA would acknowledge that TVA management was ultimately responsible for the

errors in the WBN project as opposed to TVA claiming that, as they did in Kingston, some intervening force had caused the problem was an open question.

TVA Chief Executive Officer Tom Kilgore ultimately held a press conference in April of 2012 and said that TVA had essentially miscalculated the costs and accepted

responsibility for the error. This demonstrated a new effort by TVA management to be transparent and accountable with its stakeholders. As a result, TVA replaced senior management on the project, performed a comprehensive review of the project, and publicly reported the revised schedule[5] and budget numbers. One of the TVA executives involved later pled guilty to unrelated federal criminal charges from a separate case investigated by the OIG.

- ***Browns Ferry Nuclear Plant Extended Power Uprate***

  In 2011, at the request of TVA management, the OIG reviewed the causes of the delays in the Browns Ferry Extended Power Uprate (EPU) project to increase generation capacity at Browns Ferry Nuclear Plant. The project began in 2001 and was expected to be completed in two to four years based on industry-wide experience; however, the project remains incomplete. The OIG concluded TVA senior management's decisions early in the EPU project were the most significant factor in the lack of progress in the project. Specifically, in 2001, senior management directed staff to keep the EPU proposal within a certain cost, requiring the staff to report an artificially optimistic scope and ultimately, leading a contractor to propose use of a methodology that was not approved by the NRC. Additionally, senior management ignored concerns of TVA engineering staff related to the feasibility and safety of the proposed methodology.

  TVA spent about $97 million on direct EPU costs and $26.5 million on incremental fuel costs since 2001. Additionally, TVA's marginal costs for replacement power ranged from $373 million to $448 million as a result of not achieving the EPU by the targeted dates. TVA executive management acknowledged cultural issues and stated they were committed to improving the culture of TVA through transformation initiatives and other actions including creating and maintaining an environment where all employees feel comfortable raising concerns to management or through any of the multiple available avenues.

Building Trust with Stakeholders

The work of the OIG is one of the most complex in the federal government due in part to the often competing interests of OIG stakeholders. In enacting the IG Act, Congress structured the powers and responsibilities of the IG so as to require intense communication not only of the "what" but the "how." In other words, both TVA and Congress are as interested in "how" the IG conducts audits, evaluations, and investigations as they are in the types of audits, evaluations, and investigations that we do. At the heart of this communication both with TVA and with Congress is often an unspoken question around what the intent of the IG is in allocating resources to one area of audit or investigation but not another. Here, over communicating becomes essential.

[5] In April 2012, the TVA Board approved a revised cost estimate and schedule for completion of WBN Unit 2. The revised estimate was between $4.0 and $4.5 billion and was forecasted to come on line by December 2015 according to 2012 reports filed by TVA with the Securities and Exchange Commission.

Every year the OIG sits down with the TVA Board and TVA management to discuss what the perceived high risks are for the agency. Given that the OIG has limited resources, we have a vested interest in reaching as much agreement as possible about what areas to target with those limited resources. We always have to exercise our best independent judgment about how we do this, but we regularly follow up on recommendations made by either the TVA Board or TVA management as to areas of focus.

For the TVA OIG, Congress occasionally expresses an interest in the OIG audits, evaluations, and investigations that give the best assessment of how TVA is doing. Occasionally, Congress will ask for specific work to be done in a particular area. Again, like with the TVA Board and TVA management, we try to accommodate Congress whenever possible while maintaining our independent judgment as an organization led by a presidential appointee of the Executive Branch of the federal government.

A complicating factor for the TVA OIG, like all federal IGs, is the statutory requirement that the work of the OIG be made public. Transparency and accountability are hallmark characteristics of any OIG and publishing our work on a public Web site is an essential part of that transparency and accountability. What is included in an OIG report and the tone used to describe what we find has been an on-going matter of interest for both TVA and Congress. Here, we have made it a practice to listen carefully to all sides and then use our best judgment about essentially what we believe is the right thing to do under the circumstances. Because our work often involves examining "gaps" in TVA processes that put the agency at risk, these "gaps" can cause TVA to suffer reputational harm once they are made public. When we publicly report on matters that cause TVA to come under public scrutiny, a natural reaction at TVA has sometimes been to question the intent of the OIG. While we can only do so much to lessen any suspicion of bad intent on our part, we have made it a practice to ask TVA or Congress to sit down with us and have as much healthy dialogue as possible.

Being objective and accurate about the facts has been our focus and ultimately has served the TVA OIG well. Our commitment to continually ask for more dialogue with both TVA and Congress springs from our belief that good government travels on trust. Our hallmark is being trustworthy. We do that by showing respect for opposing opinions; seeking out those who disagree with us to provide clarification, and ultimately by sticking to the facts. This "how" we do business is part of our identity and accounts for the good faith, on-going dialogue that we continue to enjoy with our stakeholders.

Investing in a Sustainable Culture of Innovation and Continuous Improvement for the OIG Team

Research shows that engaged employees get better results. This is true for TVA employees, and it is true for OIG employees. TVA and the OIG both rely on employee engagement surveys to assess how engaged their employees are. Due to the hard work and dedication of OIG employees, the 2015 Office of Personnel Management (OPM) Viewpoint scores for the TVA OIG show a highly engaged workforce. We believe that accountability for any government agency includes being transparent about the culture of its people. The TVA OIG results are available on our Web site at http://www.oig.tva.gov/2015_overall_report.pdf.

In 2014, American University in conjunction with the Council of the Inspectors General on Integrity and Efficiency (CIGIE) initiated a case study of the leadership principles that fostered such a healthy culture at the TVA OIG. The transition at the TVA OIG from a traditional "top down" and somewhat autocratic organization to a collaborative leadership organization produced a highly aligned and motivated team. This case study highlights the benefits of creating a healthy work environment that frees up employees to give their best to each other and to the organization.

The TVA OIG transformation has been good for TVA. Our engaged employees regularly give the type of discretionary effort that translates into better audits, better evaluations, and better investigations. Mutual trust and mutual respect within the OIG has been transported to our interactions with TVA employees. Starting at a trusting place enables

OIG employees and TVA employees to work better for the ultimate beneficiaries of their collective good work: the residents of the Tennessee Valley. We view this transformation as one of the most significant developments in the history of the TVA OIG. Sustaining that positive change requires empowering employees to invest in a healthy culture that is ultimately better for them and recognized as such by them. This is neither theory nor chance. It is hard work. It is mutual commitment of both OIG leadership and OIG employees. TVA OIG employees deserve the recognition they have received for creating a healthy and productive culture.

Fontana Lake
Photo Credit Frank Kehren

30 YEARS

PROJECTS/CASES SUMMARY

Cases & Reviews	Identified Costs	Recovered/Saved
12,600+	$2.35B[1]	$1.05B[2]

Over the past 30 years, OIG reviews have focused on helping TVA improve the efficiency and effectiveness of TVA operations, save or recover money, and serve as a deterrent to misconduct and fraud. While the results from some reviews are difficult to quantify, the results impacted many areas of TVA including: (1) improving key business processes; (2) improving governance functions and regulatory activities; (3) improving the protection of critical infrastructure and privacy information; and (4) improving the effectiveness of risk mitigation activities on areas of high risk. Even without a monetary value attached, these reviews provide information to help TVA operate in the most efficient manner and avoid losses from risks that are not properly mitigated. In addition, much of our reviews, primarily in the contract compliance audits and contract preaward reviews and certain investigations, have helped TVA recover and save substantial money. Highlights of audit, evaluation, and investigation activities as well as results follow.

1985 — TVA OIG was established and Norman A. Zigrossi was named TVA's first IG

1988 — President Ronald Reagan signed legislation making the TVA OIG and 32 others statutory IG offices

1996 — TVA OIG Special Agents become deputized by the U.S. Marshal

[1] Identified Costs: Sum of investigative waste identified, investigative recoveries/projected savings and audit/evaluations findings.
[2] Recovered/Saved: Sum of investigative recoveries/projected savings and audit/evaluation recoveries/savings.

PROJECTS/CASES DETAIL

30 YEARS

Investigations

9,900+ Cases Closed

Prosecutive Actions

- **342** Indictments
- **24** Pre-Trial Diversions
- **332** Convictions

Management Actions

- **1,270** People Disciplined
- **900+** Process Improvements
- **6** Debarred Vendors

Audits/Evaluations

2,700+ Projects Completed

- **2,100** Reports Issued
- **600** Other Projects

Waste identified

$507M

Recoveries/Projected Savings

$219M[3]

Findings

$1,622M[4]

Recoveries/Savings

$826M[5]

2000 — In November 2000, President Bill Clinton signs into law a bill making TVA's Inspector General a presidentially appointed position

2002 — The Homeland Security Act is passed and gives law enforcement authority to TVA OIG Special Agents

2003 — Richard Moore becomes the first presidentially appointed TVA IG

[3] Investigative recoveries/projected savings: Sum of investigative recoveries and savings/projected savings .
[4] Audit/Evaluation findings: Sum of questioned costs and funds to be put to better use.
[5] Audit/Evaluations recoveries/savings: Sum of questioned costs recovered by TVA and savings realized by TVA.

AWARDS

1999 Award

- Special Agent James F. Farr received a citation for outstanding work in a Health Care Fraud Case presented by the Special Agent in Charge of the Knoxville Division of the FBI.

2000 ECIE Awards

- George T. Prosser, IG, for outstanding contributions to the IG community.
- G. Donald Hickman, AIGI, Investigations, for his leadership and sustained contributions to the law enforcement community.
- Tool Management Program Team for outstanding teamwork and efforts in a complex audit/investigation of fraud related to TVA's Tool Management Program.
- Work in resolving a complex product substitution case.
- Workers' Compensation Team for their achievements in identifying and eliminating fraud in TVA's workers' compensation program.
- Environmental Crimes Joint Task Force for outstanding work in fighting environmental crimes from July 1, 1999, to June 30, 2000.

2001 ECIE Awards

- Clean Air Compliance Program Team for their contribution to TVA's Clean Air Compliance Program.
- Significant Review and Analysis Conducted at the Request of Congress Team for their work in conducting a congressionally requested review and analysis of power rate and cost issues.
- Office Space Team for their outstanding contributions toward improving TVA's decision-making processes related to property and office facilities.
- Investigation Regarding a Senior Manager's Misconduct Team for working together to develop, analyze, and report complex findings regarding significant misconduct by a senior manager.
- The East Tennessee Health Care Fraud Team for outstanding teamwork in a multi-agency effort to investigate and prosecute health care fraud by a medical provider in the Federal Judicial District of Eastern Tennessee.

2002 PCIE Award

- Long-Term Bulk Power Trading Team for producing two highly complex reviews of TVA's weekly, monthly, seasonal, annual, and multi-year trading in the wholesale electricity market.

2005 PCIE Award

- SOX Review Team for performing process-control reviews to assist TVA management in evaluating the design and operating effectiveness of financial reporting controls.

2006 PCIE Awards

- Fraud Risk Assessment Team for developing and implementing an action plan to perform fraud risk assessments, innovative and valuable tools to prevent and detect waste, fraud, and abuse.
- Contract Audits Team for using proactive and innovative best practices to consistently identify significant cost savings, recoveries, and process improvements for TVA.

30 YEARS

2007
PCIE Award

- Initiation of best practices sharing sessions with other OIGs.

2008
PCIE Awards

- IT Organizational Effectiveness Audits Team for work on reviewing the effectiveness of TVA's IS organization and IT Security function.
- An Investigations and Audit Team, working jointly, on a product substitution case that resulted in a $25 million recovery.

2009
Award

- Joint investigation of a complex loan fraud that resulted in the conviction of two Tennessee businessmen for bank fraud, mail fraud, and money laundering.

2010
Awards

- The National Association of Government Communicators recognized the TVA OIG fraud video as one of the 2010 winning entries of the Blue Pencil & Gold Screen Awards Competition.
- The poster advertising the TVA OIG's fraud video received two ADDY awards for color photography and the Bronze Citation of Excellence.

2011
CIGIE Award

- A review of TVA's Dam Safety Program to identify if TVA adequately addressed significant risks and was in compliance with applicable laws and regulations.

2013
CIGIE Awards

- A joint investigation and inspection identifying and notifying TVA that the WBN Unit 2 construction project was behind schedule and over budget.
- An investigation leading to the conviction of a contractor company's nuclear plant safety manager who falsified injury rates at TVA nuclear plants to collect more than $2.5 million in safety bonuses.

2014
Award

- Senior Special Agent Meagan Sands receives award from the U.S. Attorney's Office for her exemplary performance as a law enforcement agent in two notable cases.

NOTEWORTHY UNDERTAKINGS

TVA OIG Hotline Redesign

The OIG's hotline, the EmPowerline, was created to facilitate the expression of concerns by TVA employees, contractors, and the general public related to fraud, waste, and abuse in TVA programs. EmPowerline is administered by a third party, and users can anonymously report concerns anytime by phone or online.

In an effort to educate potential complainants about fraud, we created videos that inform users about the process of reporting fraud, waste, and abuse and what fraud looks like. This effort also included redesigning the EmPowerline Web site with a more simple, straight-forward design.

During July 2015, we launched the retooled Web site, which features three primary links. The first link directs users to a video that explains what happens when fraud is reported to the OIG. The second link leads to an online form to report a concern confidentially or anonymously with the OIG. The third link leads to a series of brief videos providing examples of what fraud may look like at TVA. The videos were produced by TVA's Digital and Creative Services and are based on past TVA OIG cases. TVA OIG also created a poster that has been distributed throughout the Valley to accompany the launch of the new Web site. It encourages employees and contractors to "Watch, Learn, and be EmPowered."

OIG Supports the Community through Acts of Caring

In recognition of TVA OIG's 30th anniversary, our office participated in community service days and supported the charities of Habitat for Humanity (Habitat), Ronald McDonald House, and Second Harvest Food Bank (Second Harvest) in addition to charities included in TVA's Combined Federal Campaign drive.

OIG employees are supporting the Ronald McDonald House through household donations, including toiletries, that are provided to families of children receiving life-saving medical care who are residing in nearby homes provided by the charity.

The Days of Service involved physical labor to support Habitat and Second Harvest. On October 8, 20, and 22, TVA OIG employees gathered at the Habitat warehouse in Knoxville, Second Harvest in Knoxville, and at a Habitat building site in Chattanooga, respectively. The Knoxville Habitat team worked on building sheds and shed doors as well as painting columns and sorting nails for working

families who are receiving assistance from Habitat in buying their first constructed home. The Second Harvest team worked on bagging cereal and labeling cans – bagging 2,667 cereal bags that were to be provided to hungry families in the area and labeling some 3,756 cans. The Chattanooga Habitat team worked at a homesite installing a deck and painting and repairing wood to benefit a family receiving assistance from Habitat.

"I really enjoyed being out of the office and engaging in that kind of physical work with OIG team members for a worthy cause," said OIG IT auditor Michael Newport, of his participation in the first Day of Service. "It's a gratifying experience to come together and serve our community and be able to see the results of your efforts right there on the spot, knowing it will make a difference to families in the community."

EXECUTIVE OVERVIEW

This semiannual report to Congress reports on a theme that is our vision to make TVA better. In understanding the role of an IG, this simple statement clarifies our mutual purpose with TVA. In this edition, our intention is to guide the reader through the ways our office continues to support TVA in achieving its operational goals while keeping an eye toward its greatest assets—its employees—in optimizing their abilities to contribute to TVA's operational performance and outcomes, ultimately benefitting the more than 9 million ratepayers served by TVA throughout the Tennessee Valley. This edition focuses not only on what we do, but why we do it and highlights our office's contributions since its inception, some 30 years ago on October 18, 1985.

AUDITS

The TVA OIG Audit organization completed 22 audit, review, and agreed-upon procedures engagements. This work identified nearly $7.6 million in questioned costs for TVA to recover and $2.1 million in funds the company could put to better use. We also identified several opportunities for TVA to improve the effectiveness and efficiency of its programs and operations.

Contract Audits

To support TVA management in negotiating procurement actions, we completed a review of the cost proposal submitted by a company to provide hydro modernization, unit rehabilitation, and functional support services in support of TVA's hydro facilities. Our review identified $2.1 million of potential savings opportunities for TVA to negotiate. We also completed three compliance audits of contracts with expenditures totaling $113.1 million related to (1) engineering, licensing, construction, and startup operation services in support of completion of TVA's Bellefonte Nuclear Plant; (2) environmental services for Kingston Fossil Plant; and (3) remediation work at Blue Ridge Dam. These audits identified potential overbillings of $7.6 million. In addition, we completed audits of (1) TVA's invoice approval process and (2) a contractor's potential rework and damages liability in association with work performed at WBN Unit 2. The Contract Audits section begins on page 37 of this report.

Corporate Governance and Finance Audits

With a focus on TVA's regulatory activities, compliance with applicable laws and regulations, and financial reporting, we completed audits of TVA executive incentives and overtime at TVA. In addition to our audit work, we monitored the work of the external auditor in its review of TVA's second and third quarter financial information for fiscal year (FY) 2015 to assure compliance with *Government Auditing Standards*. We also provided assistance to the external auditor during interim testing for the year-end financial statement audit. The Corporate Governance and Finance Audits section begins on page 38 of this report.

IT Audits

IT Audits (1) completed four IT organizational effectiveness audits, (2) assessed electronic communication practices of the TVA Board, (3) reviewed the implementation of a new system managing TVA's coal supply chain as well as an upgrade to an enterprise application, and (4) conducted an application audit of a system included in the process for controlling physical access to TVA assets. The IT Audits section begins on page 40 of this report.

Operational Audits

Operational Audits completed reviews of (1) TVA's process for developing its IRP, (2) the efficiency of TVA's hiring process, (3) the effectiveness of TVA's process for addressing nuclear emerging regulatory issues, (4) compliance with TVA's Obtaining Things of Value protocol, (5) the contractor workforce management process, and (6) TVA's compliance with green power accreditation requirements. The Operational Audits section begins on page 42 of this report.

STATISTICAL HIGHLIGHTS

April 1, 2015 - September 30, 2015

Audit Reports Issued	22
Evaluations Completed	6
Questioned Costs	$7,598,913
Questioned Costs Agreed to by TVA	$2,156,279
Questioned Costs Recovered by TVA	$2,981,453
Funds to be Put to Better Use	$2,106,300
Savings Realized by TVA	$142,000
Investigations Opened	126
Investigations Closed	142
Recoveries/Fines/Savings/Projected Savings	$3,025,204
Criminal Actions	2
Administrative Actions (No. of Subjects)	14

EVALUATIONS

During this semiannual period, Evaluations completed six reviews. These evaluations included reviews of (1) TVA transmission fire protection, (2) Hydro Generation fire protection, (3) Hydro Generation obsolete equipment, (4) nuclear outage performance, and (5) firearms and ammunition. The other review completed during this period is not included due to its sensitive nature. The Evaluations section begins on page 46 of this report.

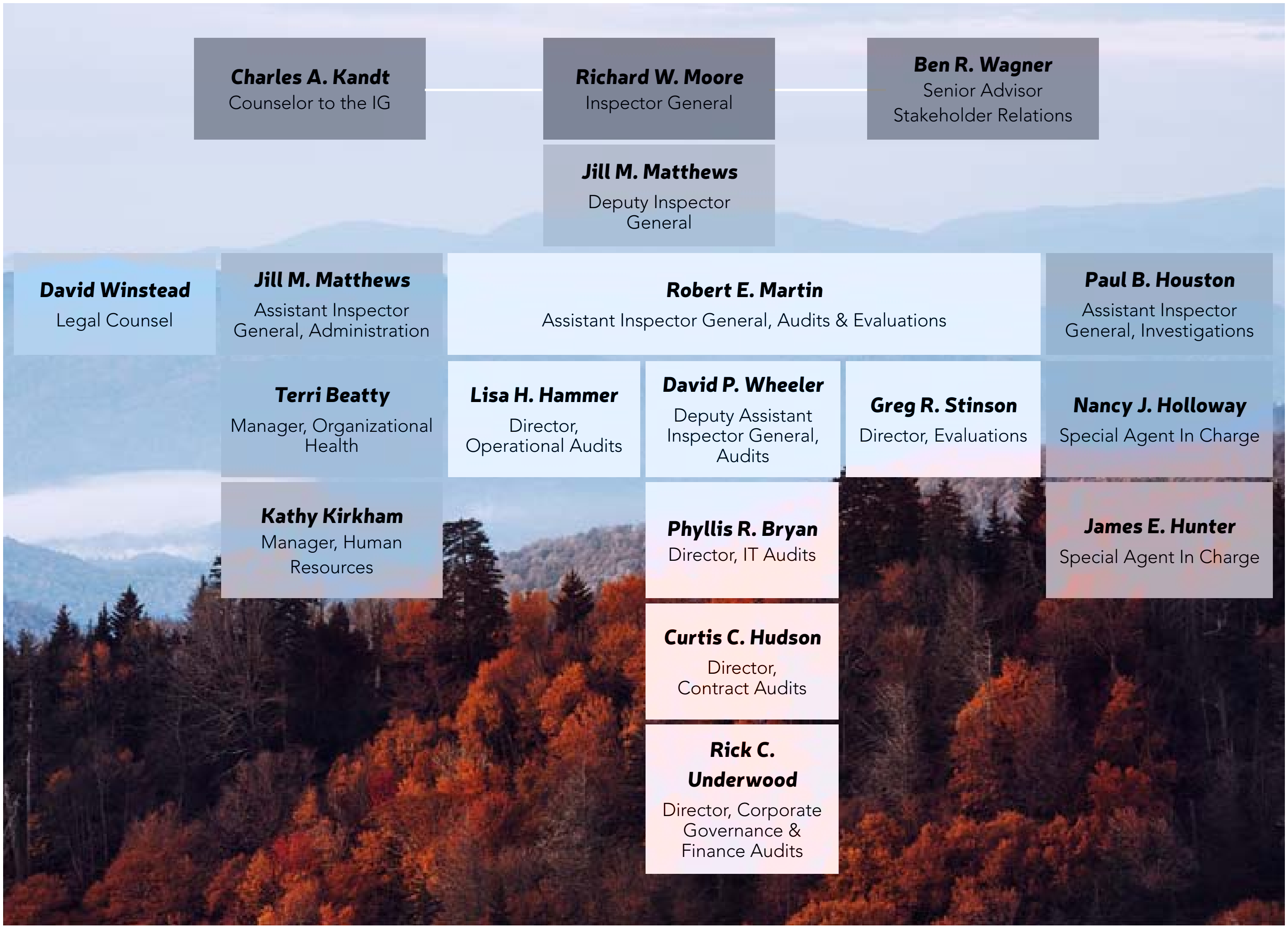
INVESTIGATIONS

This reporting period, we opened 126 cases and closed 142. Our investigative results include recoveries, savings, fees, and projected savings of more than $3 million, one indictment, and one conviction. The Investigations section begins on page 50 of this report.


Fontana Dam
Photo Credit Frank Kehren

Bull Run Fossil Plant

ORGANIZATION



Since 1985, the OIG has worked to help TVA become better which is the OIG mission. Through our audits, evaluations, and investigations, we provide TVA management, the TVA Board, and Congress with an independent look at the economy, efficiency, and effectiveness of TVA programs and help prevent and detect fraud, waste, and abuse. Over the years, the OIG has helped TVA save or recover millions of dollars and recommended numerous program improvements. We credit our success to the efforts of our hardworking and talented staff and the professional responsiveness of TVA management to our recommendations.

TVA OIG Office Locations

The OIG has a work philosophy of being in the right place at the right time to do the best work possible. We support that philosophy by encouraging our OIG employees to work where they can be most effective whether that is in one of our physical offices, in the field, or in one of our virtual offices that enable our employees to telework from home or while traveling.

The OIG has strategically located its offices near all major TVA offices throughout the Tennessee Valley. We are headquartered in TVA's East Tower, opposite TVA's corporate offices, overlooking downtown Knoxville.

The OIG has field offices in Chattanooga, Tennessee, where the Evaluations unit, members of the Corporate Governance and Finance team, and several special agents are located, as well as in Nashville, Tennessee, and Huntsville, Alabama. We also have office locations at Watts Bar Nuclear Plant in Spring City, Tennessee; and Sequoyah Nuclear Plant in Soddy Daisy, Tennessee. Staff work in these locations as needed. As of September 30, 2015, the OIG had a total staff of 106.

ADMINISTRATION

The Administration team works closely with the IG, Deputy IG, and Assistant IGs to address the day-to-day operations of the OIG and to develop policies and procedures designed to drive and enhance productivity in achieving office goals. Responsibilities include personnel administration, budget and financial management, purchasing and contract services, facilities coordination, training event planning, communications facilitation, and IT support.

AUDITS AND EVALUATIONS

The Audits and Evaluations teams perform a wide variety of engagements designed to promote positive change and provide assurance to TVA stakeholders. Based upon the results of these engagements, the Audits and Evaluations teams make recommendations to enhance the effectiveness and efficiency of TVA programs and operations.

TYPES OF AUDIT & EVALUATION ISSUES

Corporate Governance and Finance Audits
- Internal Control Deficiencies
- Program Inefficiencies/Ineffectiveness
- Policy Noncompliance
- Fraud

Operational Audits
- Operational Inefficiency
- Not Achieving Intended Results
- Inferior Performance
- Legal/Regulatory Noncompliance
- Fraud

IT Audits
- Internal Control Deficiencies
- Policy Noncompliance
- Integrity of Data and Assets
- Fraud

Evaluations
- Internal Control Deficiencies
- Operational Inefficiency
- Policy Noncompliance
- Fraud

Contract Audits
- Inflated Proposals
- Contract Overpayments
- Inferior Performance
- Fraud

The teams use an impact- and risk-based approach to develop an annual work plan. In developing the plan, the OIG considers TVA's strategic plans, major management challenges, TVA's ERM process, and other input from TVA management. This planning model also evaluates each potential engagement from the standpoint of materiality (i.e., costs or value of assets), potential impact, sensitivity (including public and Congressional interest), and the likelihood it will result in recommendations for cost savings, recovery of dollars, or process improvements. The result of the OIG Audits and Evaluations planning process is a focus on those issues of highest impact and risk to TVA.

The Audits team, primarily based in Knoxville, generates and oversees comprehensive financial and performance audits of TVA programs and operations, providing an inclusive picture of TVA's overall fiscal and operational health. This team is made up of four departments—Contract Audits, Corporate Governance and Finance Audits, IT Audits, and Operational Audits. This team performs its work in accordance with *Government Auditing Standards.*

- Contract Audits has lead responsibility for contract compliance and preaward reviews. In addition, this team performs reviews of TVA contracting processes and provides claims assistance as well as litigation support.

- Corporate Governance and Finance Audits has lead responsibility for oversight of TVA's (1) financial statement audit and related services performed by TVA's external auditor and (2) regulatory activities. This team also conducts operational reviews to assess the results, as well as the economy and efficiency of TVA programs.

- IT Audits has lead responsibility for audits relating to the security of TVA's IT infrastructure, application controls, and general controls associated with TVA systems. This team also performs operational reviews of the effectiveness of IT-related functions.

- Operational Audits focuses on risk and impact-driven operational audit work. The team performs audits of operational effectiveness and efficiency, as well as TVA compliance with laws and regulations.

The Evaluations team seeks to ensure that program objectives and operational functions are achieved effectively and efficiently. It performs both comprehensive reviews and more limited scope policy and program reviews. In accordance with the *Quality Standards for Inspection and Evaluation*, the objectives of the unit include providing a source of factual and analytical information, monitoring compliance, measuring performance, assessing the efficiency

and effectiveness of operations, and conducting inquiries into allegations of fraud, waste, abuse, and mismanagement.

Audit and evaluation issues vary depending on the objectives of the project. The graphic shows some representative examples of issues our audit and evaluation projects are commonly designed to identify.

INVESTIGATIONS

The Investigations team proactively and reactively uncovers activity related to fraud, waste, and abuse in TVA programs and operations. This team performs its investigations in accordance with the *Quality Standards for Investigations* as prescribed by the CIGIE, applicable U.S. Attorney General Guidelines, and other guiding documents. The special agents maintain liaisons with federal and state prosecutors and notify the U.S. Department of Justice whenever the OIG has reason to believe there has been a violation of federal criminal law. The special agents partner with other investigative agencies and organizations on special projects and assignments, including interagency law enforcement task forces on terrorism, the environment, health care, and public corruption, as well as securities fraud. The graphic shows the major categories of investigations.

LEGAL

The OIG Legal Counsel team monitors existing and proposed legislation and regulations that relate to the mandate, operations, and programs of the OIG and TVA. Additionally, this team provides legal advice as needed for administrative, audit, evaluation, and investigative projects.

MAJOR CATEGORIES OF INVESTIGATIONS

Contract Fraud
Defrauding TVA through its procurement of goods and services including fraud schemes such as misrepresenting costs, overbilling charges, product substitution, and falsification of work certifications.

Theft of Government Property and Services
Theft of TVA property such as material, tools, equipment, or resources.

Environmental Crime
Violations of environmental criminal law pertaining to the Tennessee River system and its watershed, along with violations relating to TVA land and facilities.

Health Care Fraud
Intentional misrepresentation of health care services, expenses, billings, needs, or coverage that results in unauthorized payments or other benefits.

Unauthorized Access Into TVA Computer Systems
Accessing a TVA computer without authorization or exceeding authorized access.

Workers' Compensation Fraud
Falsification of documents to receive payments by employees, former employees, or health care providers.

Employee Misconduct
Misuse of TVA furnished equipment, travel voucher fraud, a multitude of miscellaneous matters of abuse, conflict of interest, and violations of code of conduct.

Special Projects
Management requests, data mining and predictive analysis, Congressional and TVA Board requests, and fraud risk assessments.

SUMMARY OF REPRESENTATIVE AUDITS

During this reporting period, the TVA OIG audit organization completed 22 audit, review, and agreed-upon procedures engagements. This work identified nearly $7.6 million in questioned costs for TVA to recover and $2.1 million in funds the company could put to better use. We also identified several opportunities for TVA to improve the effectiveness and efficiency of its programs and operations.

CONTRACT AUDITS

Preaward Contract Reviews

To support TVA management in negotiating procurement actions, we completed a review of the cost proposal submitted by a company to provide hydro modernization, unit rehabilitation, and functional support services in support of TVA's hydro facilities. Our review identified $2.1 million of potential savings opportunities for TVA to negotiate. The savings opportunities were primarily related to overstated labor and burden rates and certain markup rates.

Contract Compliance Reviews

During this semiannual period, we completed three compliance audits of contracts with expenditures totaling $113.1 million and identified potential overbillings of $7.6 million. Highlights of our completed compliance audits follow.

- We audited a contractor's calendar year 2012 and 2013 rate adjustments which totaled more than $5.1 million based on $104.2 million of billed costs. The contract, which provided for the contractor to complete engineering, licensing, construction, and startup operations of a single Bellefonte Nuclear Plant unit, required the contractor to adjust its labor and general and administrative billing rates to its actual costs incurred each year. We determined the contractor's 2012 and 2013 rate adjustments were overstated by $1.8 million. In addition, we found the contractor billed more than $5.6 million in labor costs, along with associated fee, using cost-center rates not included in the contract.

- We audited $6 million in costs paid by TVA between November 14, 2011, and May 1, 2014, to a contractor for providing professional environmental services. We determined the contractor overbilled TVA $162,307, including (1) $95,425 in travel costs and (2) $66,882 in miscellaneous expenses. Additionally, we found the contractor (1) did not obtain advance written approval from TVA's Contracting Officer for $333,556 in subcontract costs billed and (2) billed TVA $32,386 using lump-sum pricing provisions not provided for in the contract.

- We audited $2.9 million in costs and fee billed by a contractor for remediation work performed at Blue Ridge Hydro Dam. TVA disputed a portion of the amount billed and requested an audit. We found the $2.9 million in costs billed to TVA were in accordance with the contract's terms and conditions. TVA and the contractor reached a final settlement on June 11, 2015, for the disputed amount.

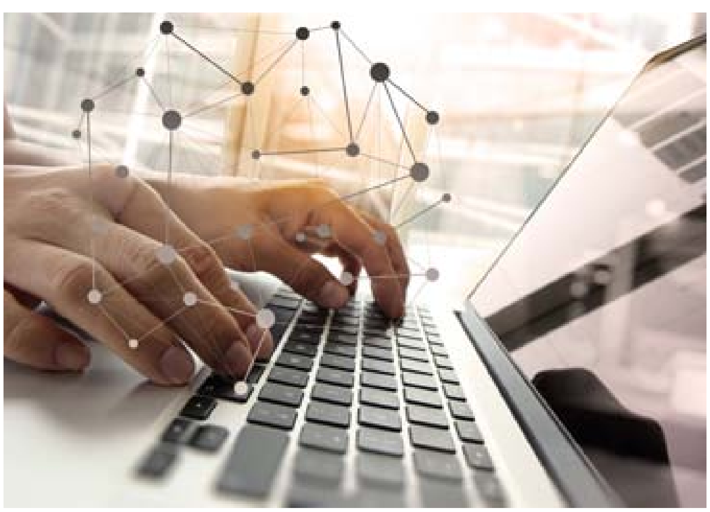
Review of Invoice Approval Process

The OIG audited TVA's invoice approval process to (1) assess TVA's policies and procedures related to the review and approval of invoices; (2) determine compliance with applicable policies and procedures; and (3) determine if TVA's invoice approvers have adequate information, including clear contractual-compensation provisions and sufficient invoice detail to effectively perform their role. Our scope included non-receiving contracts and purchase orders with FY 2013 payments totaling nearly $3.4 billion. We found policies and procedures were not followed to ensure effective review and approval of supplier invoices. Specifically, our review of 143 invoices totaling more than $184 million found inadequate reviews were performed on 104 invoices or 73 percent. Based on our review, we identified several possible underlying causes for ineffective invoice reviews: (1) contracts contained unclear and/or conflicting compensation provisions; (2) some contracts do not provide specific requirements regarding invoice detail and for those contracts that do, the requirements are not being followed or enforced; (3) not all relevant contract and purchase orders are attached to the invoice or available in TVA's Enterprise Asset Management (EAM) system; (4) the required field invoice approver (FIA) training does not include details on how to access and approve invoices in TVA's EAM system; (5) clear and frequent communication does not always exist between the FIA and contracting officer (CO); (6) an approval stamp used at a nuclear plant incorrectly implied the OIG reviews the invoices; and

(7) the current invoice review process is a manual process within an automated system.

We recommended TVA management: (1) develop a contract quality assurance program to ensure clear, concise, and easy to follow compensation terms; (2) ensure the FIAs and contract technical stewards have the most up-to-date terms and conditions of a contract by developing an approach to provide access (dependent upon business need) to contract documents; (3) require training for those accessing and approving invoices in TVA's EAM system; (4) revise policies to require the CO to confirm FIAs understand their responsibilities in approving invoices for payment; and (5) revise policies to clarify CO responsibility for monitoring the invoice approval process and verifying the contractor's invoices contain adequate detail in a format that facilitates the review.

Additionally, we recommended TVA management utilize the technology available to expedite and improve the invoice review process by implementing automated steps in the process, where possible, including: (1) requiring electronic data from vendors that allows for 100 percent review; (2) setting parameters to identify exceptions; (3) following up on items identified as exceptions before making payment on those items; (4) establishing automatic notifications be sent to FIAs, contract managers, and others regarding exceptions to ensure the exceptions are reviewed; and (5) establishing automated analytical reviews, as necessary. TVA management generally agreed with our findings and stated they would take action to address our recommendations.



Review of Contractor's Rework and Damages Liability

At the request of the TVA's Supply Chain and WBN Unit 2 construction management, we reviewed a contractor's potential rework and damages liability in association with work performed at WBN Unit 2. Our objective was to determine the reasonableness of TVA's methodology for identifying and estimating the contractor's rework and damages liability. In summary, we found TVA's methodology could be improved and recommended TVA management take actions to improve its processes for identifying and estimating the contractor's rework and damages liability. TVA management agreed with our findings and is taking action to address the recommendations.

CORPORATE GOVERNANCE AND FINANCE AUDITS

During this semiannual period, Corporate Governance and Finance Audits completed audits of (1) TVA's executive incentives and (2) employee overtime. In addition, the team provided oversight of and assistance to TVA's external auditor.

TVA Executive Incentives

In October 2014, the OIG completed an audit of TVA's executive retention. As a follow up to that audit, we initiated an audit of TVA's executive incentives to determine (1) if executive incentives align with TVA's objectives and goals and (2) whether processes for establishing executive incentive performance measures are followed.

TVA currently has two executive incentive plans, the Executive Annual Incentive Plan (EAIP) and the Executive Long-Term Incentive Plan (ELTIP), which include performance-based incentives tied to the achievement of TVA's goals and objectives. The performance measures associated with EAIP are based on the accomplishment of approved goals identified in TVA's Winning Performance Team Incentive Plan balanced scorecards. Since the performance measures associated with EAIP are not

executive specific, we focused this audit on alignment and development of ELTIP performance measures.

The OIG determined the long-term performance measures included in the ELTIP aligned with three of the five strategic imperatives included in TVA's Strategic Plan. However, we noted two of the five strategic imperatives, Debt and People and Performance Excellence, were not incentivized in the ELTIP. In our opinion, aligning long-term incentives with all strategic imperatives would (1) benefit TVA by promoting accountability in all areas identified as crucial to the achievement of TVA's mission in TVA's Strategic Plan and (2) continue to emphasize these areas as members cycle off of the TVA Board and executives leave TVA.

We also reviewed the process for establishing long-term performance measures for the ELTIP and found the process was followed by TVA and the Board. However, one potential area for improvement was noted regarding the inclusion of additional information in the plan documents that clearly describe the ELTIP performance measures development process.

Based on the findings, we made recommendations to the People and Performance Committee of the Board and TVA management to promote accountability in all areas identified as crucial to achieving TVA's mission and to provide information to their successors regarding development of executive incentive measures. The Committee and TVA management generally agreed with our findings and recommendations and provided action plans to address these issues.

TVA Employee Overtime

OIG data-monitoring efforts noted some TVA employees appeared to be compensated for unusually high amounts

of overtime. As a result, the OIG initiated a review of overtime to (1) analyze overtime payments at TVA and identify any trends or areas where overtime payments were concentrated and (2) identify individuals compensated for excessive amounts of overtime in any areas identified and determine if (a) overtime had been approved by managers and supervisors in accordance with applicable guidelines and (b) controls were in place to prevent situations where fatigue could reduce the ability of operating personnel to work in a safe condition. Our audit scope included all overtime paid at TVA from October 1, 2013, through August 31, 2014.

During our audit, we found overtime hours were not passed to TVA's payroll system for payment until these hours had been approved in TVA's time-reporting system. In addition, we determined 86 percent of the total overtime hours paid during the audit period were to employees in Transmission and Power Supply, TVA Nuclear, and Power Operations organizations. Our analysis of overtime paid for the three organizations during our 11-month audit scope noted excessive amounts of overtime being worked. Specifically, we noted 1,053 employees with at least 500 hours of reported overtime and 31 employees with at least 1,000 hours of reported overtime. Although the post approval process appeared adequate, we found inconsistent methods for documenting preapproval of overtime. Additionally, we noted TVA lacked organizational guidance for managing fatigue and work-hour limits in all operational areas other than TVA Nuclear.

We made recommendations for TVA to implement a common procedure for preapproval of overtime, develop guidance for all of TVA for managing fatigue and controlling work hours, and review positions within the organization where employees are working excessive amounts of overtime on a regular basis and determine whether safety and/or productivity are a concern. TVA management agreed with our findings and recommendations and is taking corrective actions to address these issues.

IT AUDITS

During this semiannual period, IT Audits (1) completed four IT organizational effectiveness audits; (2) assessed electronic communication practices of the TVA Board; (3) reviewed the implementation of a new system managing TVA's coal supply chain, as well as an upgrade to an enterprise application; and (4) conducted an application audit of a system included in the process for controlling physical access to TVA assets.

IT Organizational Effectiveness Audits

A key aspect of the TVA mission and vision is to provide affordable electricity to rate payers. TVA's IT organization's contribution to this mission and vision includes operating effectively. Accordingly, to assist IT in increasing its effectiveness, the recommendations from our previous organizational effectiveness audit were focused on creating sustainable processes. In addition, TVA's Chief Information Officer created a program titled 1,000 Days to Success (IT1K) to address findings from the audit as well as other observations he made as to the current state of IT.

Currently, we are conducting a series of audits to assess the IT organizations' (1) current effectiveness, including alignment with TVA values; (2) sustainability of actions taken in response to the 2011 OIG audit; and (3) outcomes of the IT1K program. To date, we have completed audits in the following organizations within TVA IT: Enterprise Information Security and Policy; Enterprise Architecture and Programs; Operations Solutions Delivery; and Enterprise Customer Operations.

In summary, we found:

- Enterprise Information Security and Policy operations have improved since the 2011 audit, but effectiveness could be improved around compliance and risk management activities and engagement in IT application implementation projects. Additionally, we recommended improvements around staffing within the organization.

- Enterprise Architecture and Programs also showed improved effectiveness since the 2011 audit; however, we noted program enhancements which would improve the quality of IT project delivery.

- Operations Solutions Delivery was formed as a new group within IT during a TVA reorganization conducted since the 2011 audit. We noted this group is operating at a high level of effectiveness; however, as technologies expand and support needs increase, the current staff level may need to be reassessed to continue successfully meeting customer needs.

- Enterprise Customer Operations has worked to improve the IT end-user experience by adopting industry standard best practices, building a new customer operations center, offering expanded self-services options to end users, and providing strong and constructive leadership. While the group has succeeded in many efforts, improvements are needed in the areas of physical asset management and service-level management. TVA management agreed with the findings and is taking action to implement the recommendations.

Electronic Communications of TVA Board

We performed an audit of electronic communications conducted by the TVA Board. In summary, we determined current TVA Board e-mail practices are consistent with the Presidential and Federal Records Act Amendments of 2014 federal law. In addition, we found the third-party service used to distribute sensitive documents to the Board had appropriate processes and controls in place as reported by another independent audit company. However, improvements could be made to reduce the risk of exposing sensitive TVA business information. The Board agreed with the findings and will continue to explore options around the recommendations.

Implementation Projects

We completed two audits associated with system implementation or upgrades described as follows. The first implementation project was for a new application to manage TVA's coal supply chain. In summary, we determined the TVA project team followed TVA systems development processes and included consideration of business processes during implementation. During the audit, items of potential risk and concern identified by the OIG were communicated to TVA. The project team addressed all findings by either implementing our recommendations or accepting the risk to the project prior to the time the new system went into production.

The second implementation project was to upgrade TVA's EAM system to a new version. This version upgrade provided performance improvements, reduced customizations, maintainability, and kept the TVA application at a supported level. In summary, we determined the TVA project team followed TVA systems development processes and included consideration of business processes during implementation. However, we found (1) some weaknesses in our review of two security groups, (2) group memberships were not maintained consistently, and (3) integration for historical documents was not completed. Other items of potential risk and concern were communicated to management during the audit and were addressed prior to the time the new system went into production.

TVA management agreed with our findings in both audits and is in the process of identifying or has taken actions to implement the recommendations.

Application Audit

We audited a TVA application that is part of the process for controlling access of personnel with authorized unescorted physical access to sensitive TVA assets. In summary, we determined (1) logical security controls were generally operating effectively, and (2) controls around granting physical access to sensitive TVA locations were operating in accordance with TVA policy. However, we found (1) electronic forms were not stored properly, (2) system administrator access appeared to be greater than what was needed, and (3) documentation of periodic access reviews was not maintained. TVA management agreed with our findings and is taking actions to implement the recommendations.

OPERATIONAL AUDITS

During this semiannual reporting period, Operational Audits assessed TVA's process for developing its IRP, evaluated the efficiency of TVA's hiring process, assessed the effectiveness of TVA's process for addressing nuclear emerging regulatory issues, assessed compliance with TVA's Obtaining Things of Value protocol, evaluated the contractor workforce management process, and verified TVA's compliance with green power accreditation requirements.

Integrated Resource Planning Process

The TVA developed its IRP to guide the organization in meeting future energy demands. The first IRP developed by TVA, referred to as Energy Vision 2020, was published in December 1995. The stated purpose of this IRP was to be a "roadmap for meeting the energy needs of its customers for the next 25 years with economical and environmentally sound energy choices." In March 2011, TVA issued a 20-year IRP referred to as TVA's Environmental and Energy Future. The purpose of the March 2011 IRP was to aid TVA in becoming one of the nation's leading providers of low-cost and cleaner energy by 2020. Additionally, TVA published a Supplemental Environmental Impact Statement (SEIS) reflecting the potential impacts of the IRP contents on the environment, as required by the National Energy Policy Act of 1992.

TVA personnel updated the IRP in 2015 due to significant changes in the electric industry and within TVA. These changes included abundant natural gas supplies from shale deposits, a decline in electricity demand growth across the industry and within the Tennessee Valley, a new schedule for completing WBN Unit 2, TVA's clean-air commitments,[6] industry changes in areas such as distributed generation and energy efficiency and demand response, and more stringent environmental requirements. In addition to updating the IRP, TVA personnel updated the 2011 Environmental Impact Statement and issued the 2015 SEIS.

TVA's current IRP, issued in draft in July 2015 and approved by the TVA Board in August 2015, is considered by TVA personnel as "a comprehensive study of how TVA might meet future energy and capacity needs beyond what can be met with existing energy resources in a variety of future environments." The goal of the IRP is to balance the objectives of TVA's overall mission while ensuring a diversified electricity-generation mix.

We evaluated the adequacy of TVA's development process for the 2015 IRP, including demand-side and supply-side strategies. The scope of the audit included commencement of the IRP process on October 31, 2013, through IRP approval by TVA's Board on August 21, 2015, and the corresponding SEIS. To evaluate the adequacy of the IRP process, we attended IRP team meetings and meetings with external stakeholders to observe the vetting of

[6] These commitments included the retirement of less-efficient coal capacity by 2019, which resulted from a settlement with the Environmental Protection Agency, effective June 13, 2011.

decisions made in the development of the IRP. We also compared IRP inputs to authoritative industry sources, such as the Energy Information Administration, and assessed benchmarking information provided by TVA's consultant. At specific milestones within the IRP process, we provided the analysis of those observations to TVA so recommendations could be implemented throughout the process. Based on our observations and work performed, we determined TVA's process for developing the 2015 IRP was adequate in considering potential future uncertainties and associated responses. Specifically, we determined the IRP project team met stakeholder input objectives by engaging numerous stakeholders and incorporating public opinions into the development of the IRP. We also determined the IRP team considered project risks, including those related to project management, and incorporated practices commonly seen in integrated planning processes, as well as best practices, into the IRP.

In our opinion, the IRP team improved integrated resource planning efforts as lessons learned from the development of the 2011 IRP that were incorporated into the 2015 IRP. Additionally, we determined that scenario and strategy development and consideration of IRP inputs were consistent with those of other organizations. Our assessment of steps taken to analyze and evaluate the IRP, including development of metrics and to develop the SEIS, found actions were reasonable.

TVA's Talent Acquisition and Deployment Process

At the request of the Vice President of Human Resources (HR), we evaluated the efficiency of the hiring process related to time-to-fill for TVA annual employee positions. In addition, we assessed TVA's reporting capabilities and functionality to identify gaps within the talent acquisition and deployment process. Time-to-fill is measured from the time the need to hire an employee is identified until the person is available to start work at TVA. Our audit scope covered the hiring process as of August 2014 for internal and external candidates and direct-fill and competitive positions filled from January 2014 through August 2014.

We found (1) process inefficiencies that can extend the hiring process and (2) issues impacting the usefulness of the time-to-fill metric. In addition, we identified areas where TVA's HR information system could be improved to better support the hiring process and two areas where TVA did not comply with OPM requirements related to Selective Service registration and internal requirements for psychological evaluations for system operators and dispatchers.

Additional matters, not directly related to our audit objectives or within the scope of our planned audit, came to our attention during the audit related to completing psychological evaluations and motor vehicle checks for certain positions. TVA management generally agreed with our recommendations and provided planned actions for addressing those recommendations.

Effectiveness of TVA's Process to Address Nuclear Regulatory Risk

In TVA ERM's FY 2013 fourth quarter documentation, we noted TVA's Nuclear Power Group (NPG) had identified several risks associated with compliance with regulatory requirements. Based on the identified risks, we initiated an audit related to TVA's nuclear regulatory program to assess the effectiveness of TVA's process for addressing nuclear emerging regulatory issues (ERI). TVA defines an ERI as "…an external development that may result in significant impact to NPG resources. This typically includes changes to nuclear regulations or the nuclear operating regulatory environment that could affect NPG's performance or require a modification to its business or operating practices." For purposes of this audit, we limited our scope to NRC proposed rulemaking. Specifically, our audit covered TVA's process for identifying, tracking, and monitoring potential NRC rules and regulations that could be applicable to TVA. Accordingly, we did not include in our audit scope TVA's process for complying with newly-enacted or previously-enacted NRC rules and regulations.

We determined the process for addressing nuclear ERIs is generally effective. During the period of our review, September 26, 2009, through September 26, 2014, we identified no instances where TVA overlooked an

ERI related to NRC-proposed rulemaking; however, we did identify areas where TVA's internal policy related to emerging regulatory issues was not being followed. Specifically, (1) the ERI Monitoring Table was not being filled out completely and consistently, (2) formal executive briefings were not consistently occurring, and (3) executive sponsors were not being assigned to ERIs with significant impacts on NPG resources. As a result of our audit, TVA began taking corrective action by issuing a revised internal procedure.

We also noted two opportunities to improve the effectiveness of the process related to providing additional dates and explanations to the ERI Monitoring Table and enhancements to keep the list of industry working groups and participants as up-to-date as possible. TVA management agreed with our recommendations and provided planned actions for addressing those recommendations.

Obtaining Things of Value from TVA

In August 2008, numerous newspaper articles questioned the fairness of a TVA Maintain and Gain[7] transaction granting water access to Blackberry. Blackberry's primary investor was a congressman who served on the U.S. House Transportation Committee's Subcommittee on Water Resources and the Environment, a Congressional panel that provides formal oversight of TVA. The articles raised questions about whether the congressman used his position to influence TVA's decision to grant Blackberry's request for water access. Because doubt was cast on the fairness of a TVA process, the TVA OIG conducted an inspection and found no evidence of pressure on TVA from the congressman to give Blackberry water access on this lakefront project.

As a result of that inspection, TVA and the TVA Board agreed to develop a policy to provide a means to identify the potential of actual or apparent conflicts of interest or the appearance of the exertion of undue influence on the part of a person applying for a TVA benefit. TVA developed the "Obtaining Things of Value from TVA Protocol" (Protocol) in June 2009. According to the Protocol, its purpose is to ensure that "when something of value is being sought from TVA, the decision-making process needs to be fair, impartial, transparent, and evenhanded, both in fact and in appearance."

The Protocol requires the applicant requesting a "thing of value" to self-disclose whether a "covered person" stands to benefit if the request is approved. According to the Protocol, a "thing of value" is defined as (1) any interest in real property held by TVA in the name of the U.S., (2) any Section 26a permit,[8] (3) a sole-source contract with a monetary value greater than $25,000, (4) a donation with a monetary value greater than $10,000, or (5) surplus or excess property with a monetary value greater than $10,000. A "covered person" is defined as any of the following individuals or an immediate family member of any one of the following individuals: (1) an elected government official, (2) a policy-making level employee of an entity that regulates TVA or its activities, (3) a management-level employee of a power customer of TVA, (4) a TVA director, or (5) a TVA employee.

The Protocol includes a process to handle requests and inquiries related to a "covered person" requesting a "thing of value," including documenting any communication with the "covered person." The Protocol requires this information be disclosed to the Chief Ethics Officer and the OIG. The Chief Ethics Officer's role is to review the information to ensure the covered persons' transactions are "fair, impartial, transparent, and evenhanded, both in fact and in appearance." The OIG also receives covered persons' request notifications for additional independent oversight.

This audit was initiated to determine whether the Protocol (1) design provides reasonable assurance of meeting its intended purpose and (2) was implemented as required.

[7] The Maintain and Gain program was designed to allow consideration of proposals to obtain lake access rights at the landowner's property by swapping access rights already available at other properties the landowner may possess. The policy, as written, required the transactions to result in no net loss or, preferably, a net gain of public shoreline to TVA.

[8] Section 26a of the TVA Act, passed by Congress in 1933, requires TVA approval be obtained before any construction, operation, and maintenance activities can be carried out that affect navigation, flood control, or public lands along the shoreline of the TVA lakes or in the Tennessee River or its tributaries. Examples of structures and projects that require TVA approval include boat docks, piers, boat ramps, shoreline or stream bank stabilization, bridges, culverts, commercial marinas, barge terminals and mooring cells, water intake and sewage outfalls, and fill or construction within the river floodplain. These requests are called Section 26a permits.

We determined the design does not provide assurance of meeting its intended purpose and the Protocol was not implemented as required. Specifically, the Protocol does not provide assurance TVA is reducing the risk of undue influence. We found the Protocol: (1) was not effectively designed to meet its intended purpose; (2) was not consistently incorporated into TVA policies and procedures and instances of noncompliance with some Protocol requirements are occurring; (3) contains no consequences for the applicant's noncompliance with self-disclosure; and (4) contains no instructions on how an employee is to disclose knowledge of actual or apparent undue influence related to the Protocol limits, reducing the likelihood of identifying and preventing actual or apparent undue influence. In addition, we identified additional improvements to the Protocol documentation.

TVA's Contractor Workforce Management (CWM)

The TVA relies on a combination of TVA employees and contractors to meet its labor needs. We audited TVA's Contractor Workforce Management (CWM) process for acquiring craft and noncraft staff augmentation labor to determine (1) whether the process was operating as intended and (2) risks were being adequately mitigated. The process' intended purpose, according to TVA's CWM policy, is to "maintain the highest performing contractor workforce at the lowest total cost of ownership."

We found no assurance the process is operating as intended, and some risks are not adequately mitigated. Specifically, we found (1) the process is primarily a mechanism for acquiring and processing contractor employees to augment TVA staff rather than a process to ensure TVA's broader objective of maintaining a high performing, low-cost contractor workforce; (2) controls around the duration of contractor employment can be improved; (3) numerous exceptions to a control that capped noncraft staff augmentation contractor salaries were being granted; (4) hiring managers were able to choose job positions in the system with higher pay rates than the position actually being filled; (5) performance metrics specific to the CWM process were not being calculated; and (6) contractor data inaccuracies and errors exist within TVA's HR system and contractor hiring and invoicing system.

We also identified three CWM process risks that, in our opinion, may not be adequately mitigated. These risks include:

- Opportunity to avoid TVA's Citizenship Requirements policy.
- Potential for unintended employer-employee relationships.
- Reliance on contractors to comply with U.S. Citizenship and Immigration Services guidance.

We made recommendations to TVA management. TVA management agreed with our recommendations and is taking corrective action.

Verification of TVA's Compliance with the Green Pricing Accreditation Program Requirements for Calendar Year 2014

TVA's Green Power Switch Program supports the production of electric power from renewable resources such as solar, wind, and methane gas, and adds such sources to TVA's power mix. TVA certifies the Green Power Switch program with the CRS which promotes the development of renewable energy. The OIG completed agreed-upon procedures to assist the CRS in determining TVA's compliance with the annual reporting requirements of the CRS Green Pricing Accreditation Program for the year ended December 31, 2014.

These procedures included steps to verify the renewable energy supply was sufficient to meet sales; products met the Green-e criteria and stated product content; and marketing as well as product information was accurate and communicated to customers. The results of the procedures verified that TVA's Green Power sales were based on electricity generated or acquired from eligible renewable sources and otherwise met the above aspects. CRS was provided with results of the procedures applied.

SUMMARY OF REPRESENTATIVE EVALUATIONS

During this semiannual period, Evaluations completed six reviews in the areas of Hydro Generation obsolete equipment, Nuclear outage performance, fire protection systems at Transmission and Hydro Generation facilities, and firearms and ammunition. One review is not included in this discussion due to its sensitive nature.

Hydro Generation Obsolete Equipment

Based on TVA's aging equipment and the risk of parts being unavailable, we scheduled a review of Hydro Generation obsolete equipment. The objective of our review was to determine if Hydro Generation is effectively managing obsolete equipment.

According to TVA, though hydroelectric power is only about 10 percent of TVA's power generation capacity, its value to the TVA system cannot be measured by megawatts alone. Hydropower has other advantages that make it extremely valuable in an increasingly competitive utility industry where low-cost generation and reliable service are critical priorities. TVA has 29 conventional hydropower plants with 109 individual units, which play a vital role in achieving TVA's mission of providing affordable and reliable electricity, managing a thriving river system, and supporting sustainable economic development.

During our review, we found Hydro Generation could more effectively manage obsolete equipment. We found no documented guidance to specify how obsolete equipment should be managed. In addition, we found obsolete equipment has extended outage durations. We also found some equipment condition assessments include an "Availability of Spare Parts" indicator, which measures the availability and willingness of the original equipment manufacturer to support existing, installed equipment with parts and service; however, it is not included in the condition assessments for all equipment. TVA management agreed with our recommendations and is taking corrective action.

Nuclear Outage Performance

This review was initiated to assess recent efforts of the TVA NPG to improve outage performance. The objective of the review was to determine whether (1) the initiatives implemented by the NPG to improve outage performance have achieved planned results and (2) current improvement efforts are adequate.

TVA's three nuclear plants contribute about 6,600 megawatts of electricity, about 30 percent of TVA's power supply, to the power grid, making the NPG an integral part of the seven-state power system. According to TVA, as nuclear performance improves across the industry, NPG's challenge is to continue its mission to ensure safe plant operations and achieve its vision of being the best multi-site, nuclear power operator in the world.

According to the International Atomic Energy Agency, the competitive environment for electricity has significant implications for nuclear power plant operations including, among others, the need for efficient use of resources and effective management of plant activities such as on-line maintenance and outages. Nuclear power plant outage management is a key factor for good, safe, and economic nuclear power plant performance. There are many aspects to outage management including plant policy, coordination of available resources, nuclear safety, regulatory requirements, technical requirements, etc. TVA's NPG had recent initiatives aimed at improving outage performance, the main measures of which include dollars, duration, and dose. Current goals for refueling outages are to meet or exceed industry top quartile of less than 29.67 days duration and operations and maintenance cost of less than $36 million.

We found cost structure development and controls initiatives have improved outage performance with respect to cost; however, outage duration and dose continue to miss business plan goals. Additionally, we found outage performance initiatives have continually changed and excellence/improvement initiative plans do not include all planned actions. While some initiatives have been completed, others are ongoing and have rolled over to different plans, making it challenging to tie changes to measurable results. TVA management agreed with our recommendations and is taking corrective action.

Transmission Fire Protection

Fires in substations can severely impact the supply of power to customers and utilities' revenue and assets. These fires can also create a fire hazard to utility personnel, emergency personnel, and the general public. There are 14 sites

managed by Transmission that have fire protection systems to protect their 500-kilovolt transformers. This review was initiated based on findings from a previous review of fire protection at coal plants. The objective of this review was to determine if fire protection systems are established and maintained to effectively manage fires within the TVA transmission system.

According to TVA management, fire protection systems have been established where needed; however, the current systems have antiquated equipment that is being replaced as funding allows. These upgrades do not include modifying the water supply. The current system's water supply does not meet National Fire Protection Association code or TVA policy requirements. However, TVA management indicated that TVA is not required to meet national code. The risk fire protection systems will not function effectively is increased because of the condition of systems and the systems not meeting national code or TVA requirements.

Additionally, according to TVA management, maintenance is performed or requested by personnel at the Transmission Service Center; however, maintenance is not always documented. We found there are no requirements to track the fire protection systems or their condition. In addition, the inspections that are part of the preventive maintenance program are not conducted consistently. There is an increased risk that an issue could go unrecognized if systems are not being consistently inspected and the condition tracked. TVA management generally agreed with our recommendations and is taking corrective action.

Hydro Generation Fire Protection

This review was initiated based on findings from a previous review of fire protection at coal plants. The objective of our recent review was to determine whether fire protection systems are adequately maintained and mitigating actions are taken to minimize the impacts of fires at TVA hydro generation plants.

TVA's 29 conventional hydropower plants and Raccoon Mountain Pumped-Storage Plant play a strategic role in TVA's mission of providing affordable, reliable electricity, managing a thriving river system, and supporting sustainable economic development. Although TVA's hydroelectric generation is only 10 percent of generation capacity, it offers other advantages such as being emissions free and the least expensive source of generation.

While the likelihood of fire is lower at hydro plants than at coal plants, they are not without fire risk. Hydroelectric stations share many of the same fire hazards as coal plants such as oil-filled transformers, electrical cables and switchgear, air-cooled generators, and large quantities of combustible hydraulic oil. Hydro plants pose extreme safety issues and rescue risks because of limited building access, lack of natural lighting, and embedded structures, all of which increase the potential for a fire on a higher level to trap workers on a lower level.

During our review, TVA indicated that fire protection systems and equipment are generally being maintained and in good condition with some exceptions. Additionally, Hydro Generation is making improvements to condition assessments of fire protection equipment. However, we found mitigating actions to decrease the impact of fires could be strengthened in four areas: (1) risk assessment reports indicated that hydro plants could use more fire protection equipment and process enhancements to documentation of inspection, testing, and maintenance are still needed; (2) TVA indicated fire drills are being conducted on a routine basis, but are not documented as required, fire incidents are not being tracked, and lessons learned are being shared inconsistently; (3) TVA has not fully implemented the Emergency Response Liaison role; and (4) the increased risk from replacing the liaison role has not been included as a TVA enterprise risk. TVA management generally agreed with our recommendations and is taking corrective action.

Firearms and Ammunition

In response to the increasing workplace violence incidents throughout the country, we initiated a review of TVA's firearms and ammunition. TVA Police and Emergency Management (TVAP&EM) is charged with providing security and crisis/emergency management services for all TVA personnel, facilities, and other assets. Part of accomplishing this mission requires that firearms and ammunition are properly accounted for and safeguarded. The objective of our review was to determine if firearms and ammunition are properly accounted for and safeguarded. Our review found TVAP&EM is accounting for and safeguarding firearms and ammunition. Firearms not issued are safeguarded in secured storage areas; these firearms, and those issued to TVAP&EM employees, are accounted for through an annual hands-on inventory. Also, during testing, TVAP&EM was able to provide documentation for a sample of firearms either destroyed or transferred.

Our work, however, did identify opportunities for improvement in certain areas. While TVAP&EM guidelines require all TVA-issued firearms to be carried while on duty, one employee was unable to initially provide a firearm for physical inventory. Additionally, while TVAP&EM was able to provide documentation for destroyed and transferred firearms, some improvements could be made in relation to compliance with the guidelines for the documentation of transfers. Finally, there were a few instances in the guidelines regarding firearms and ammunition responsibility that did not match actual practice. TVA management agreed with two of the three recommendations and is taking corrective action. Management disagreed with the third recommendation but did change a work instruction to address the finding.

SUMMARY OF REPRESENTATIVE INVESTIGATIONS

This reporting period, we opened 126 cases and closed 142. Our investigative results include recoveries, savings, fees, and projected savings of more than $3 million, one indictment, and one conviction. Significant representative activities are following.

Related OIG Investigations Net $1 Million Recovery and $1.8 Million Savings to TVA

This investigation was initiated after TVA OIG received an allegation that a TVA contract employee had engaged in inappropriate behavior associated with his role in the TVA Energy Services Company (ESCO) program. The former TVA ESCO program provided energy efficiency services to customers such as military installations and schools.

During a previous reporting period, our investigation determined the contract employee had accepted tickets to a college football game from an ESCO vendor. In response to our findings, TVA Industrial Marketing Senior Management terminated this individual's contract and initiated a comprehensive review of the ESCO program.

Our investigation into TVA ESCO personnel regarding contract-related misconduct found, in addition to the acceptance of college football tickets, (1) misuse of government property, (2) unethical conduct, and (3) loss of confidence in ability to perform the job.

Subsequent investigation into one of the primary TVA ESCO contractors determined that one contractor had overbilled TVA and had included clearly unallowable costs. TVA Office of the General Counsel and Supply Chain management personnel were briefed on the findings and pursued a defective pricing claim. As a result, TVA and the contractor entered into a negotiated supplemental agreement whereby the contractor will repay TVA a total of $1 million.

As a result of a related OIG investigation, TVA changed associated processes and controls which led to the rebid of the contract and resulted in a savings of $1.8 million.

Ethics Violation and Document Security Breach

OIG investigative work revealed a senior executive advisor violated ethics policies by engaging in an inappropriate relationship with a TVA vendor, including coaching the vendor on how to respond to TVA to gain a competitive advantage, revealing "TVA Confidential" information involving other vendors, and making damaging comments about TVA coworkers who were part of the bidding process. We reported our findings to TVA management. The individual's employment was immediately terminated with a restriction should the individual seek reemployment at TVA.

During the course of the inquiry, we also discovered documentation the former employee had improperly disclosed to a vendor which had been obtained from TVA personnel who, in the course of their duties, routinely provided confidential data to various offices within TVA and to external entities. Those persons were not implicated in unethical behavior; however, we discovered a majority of the confidential information the former manager obtained and improperly disclosed had not been marked "TVA Confidential" as required.

We reported this finding to management; and, as a result, supervising managers in this organization completed required reading of the TVA Information Management Policy, and routine reports have been reviewed and updated to include the applicable marking as required to enhance and maintain security.

Tool Room Thefts Adjudicated

Sequoyah Nuclear Plant reported drills, saws, and other materials valued at more than $3,000 missing from its tool room. Video surveillance was reviewed, which assisted in identifying two contractor employees leaving the plant with large bags filled with unknown contents. The discharged former contractors both were indicted on one count of theft of more than $1,000 in Tennessee state court on February 19, 2014. One of the individuals made restitution to TVA of approximately $900, thus avoiding prosecution. On May 18, 2015, the other individual pled guilty to a lesser count of theft, was ordered to make equivalent restitution, and was sentenced to 11 months and 29 days of confinement; however, the sentence was suspended. Both are restricted from future TVA employment.

Former TVA Employee Indicted on Wire Fraud, Embezzlement Charges

An OIG investigation of TVA credit card abuse uncovered a variety of unauthorized payments, possibly totaling more than $60,000, to a former employee. On September 1, 2015, the former employee was indicted in federal court on charges of 10 counts of wire fraud and 1 count of embezzlement. The indictment charges the individual with using his TVA-assigned credit card to purchase hotel stays unconnected to his TVA duties and to purchase diesel fuel for third parties in exchange for cash. The final count of the indictment charges the former employee with embezzlement for converting TVA property valued at more than $1,000 to his personal use. Prosecutive action is ongoing.

Civil Agreement Garners More Than $100,000

Based on our investigation, a Valley medical provider, TVA, and the U.S. Department of Justice entered into an agreement whereby the provider paid the U.S. $123,036.38—$59,672.64 of which was paid to TVA as restitution and the remainder in penalties and fees.

The provider's patients included local TVA employees and retirees, whose medical care is ultimately paid by TVA (through BlueCross BlueShield, which administers TVA's medical benefits plan). The parties to the settlement agreed that the provider lacked documentation for several key facets of its billing during a three-year period. In addition to the settlement, the OIG investigation resulted in a projected five-year savings to TVA of $97,134, based on the provider's inability to continue past billing practices.

UPDATES

Police Corruption Probe Concluded

We previously reported six former Knoxville-area law enforcement officers, including a former TVA Police (TVAP) officer, pled guilty to misusing their positions of authority by personally receiving payment to protect high-stakes gambling, most notably a $1 million poker game during November 2009. In addition to the former TVAP officer, other former officers were members of the University of Tennessee Police Department (UTPD), the Knox County Sheriff's Office (KCSO), or the Pigeon Forge Police Department (PD).

Sentencing for all involved individuals concluded this reporting period. Two were sentenced during the prior period—the former TVAP officer to two months of home detention and three years of probation; the former UTPD officer to six months of home detention and three years of probation. During April 2015, two former members of KCSO were sentenced to two months of home detention and three years of probation. One former KCSO deputy was sentenced to one year of probation, and the former Pigeon Forge PD detective was ordered to serve nine months of home detention and three years of probation. The high-stakes poker games were one element of a long-term undercover operation conducted by the FBI with assistance from TVA OIG and other agencies.

Former TVA Vendor Debarred from Participating in Federal Contracts

As previously reported, a TVA OIG investigation resulted in former TVA vendor Frank Lewis Conn's indictment on five counts of wire fraud. Mr. Conn was an owner of a company that contracted with TVA to remove vegetation from power lines and other TVA property across the Tennessee Valley. The federal indictment alleged he devised a scheme to defraud TVA of $152,712 through the use of fraudulently inflated invoices. Based on his January 2014 guilty plea to one count of the indictment, he appeared for sentencing May 28, 2014. Mr. Conn was ordered to pay TVA $72,000 restitution and sentenced to three months of home detention and two years of probation. The judge additionally mandated he write an essay for publication in his local newspaper describing the difference between a "mistake" and a "deliberate choice."

During this reporting period, Mr. Conn and two associated businesses—Conn Equipment Rental Company, Inc., and Vegetation Management Services—were debarred from participating in federal contracts until June 30, 2018.

Nottley Dam

LEGISLATION AND REGULATIONS

Section 4(a) of the Inspector General Act of 1978, as amended, provides that the Inspector General shall review existing and proposed legislation and regulations relating to programs and operations of such establishment and make recommendations in the semiannual reports...concerning the impact of such legislation or regulations on the economy and efficiency in the administration of such programs and operations administered or financed by such establishment or the prevention and detection of fraud and abuse in such programs and operations.

In this section of our semiannual report, it is our intent to address only current and pending legislation which relates to the economy or efficiency of TVA operations when we have recommendations or comments to make to Congress regarding the legislation. At times, we may direct recommendations to general positions and issues, particularly when there are multiple bills dealing with the issue. At other times, we anticipate making recommendations relating to particular statutes and bills and their particular wording.

During this reporting period, we are not making any recommendations to Congress regarding current or pending legislation.

Kingston Fossil Plant

APPENDICES

INDEX ON REPORTING REQUIREMENTS UNDER THE IG ACT

APPENDIX 2

OIG AUDIT REPORTS • Issued During the Six-Month Period Ended September 30, 2015

Report Number and Date	Title	Questioned Costs	Unsupported Costs	Funds Put To Better Use
CONTRACT AUDITS				
2014-15239 04/14/2015	AREVA NP, Inc. – Review of Annual Rate Adjustments – Contract No. 004027	$7,436,606	$0	$0
2014-15042 04/22/2015	Geosyntec Consultants, Inc.	162,307	0	0
2014-15031 06/23/2015	Adequacy of Invoice Approval Process	0	0	0
2014-15248 06/23/2015	Hayward Baker, Inc. – Contract No. 6902	0	0	0
2015-15309 08/04/2015	Proposal For Hydro Modernization, Unit Rehabilitation, and Functional Support Services	0	0	2,106,300
2014-15240 08/11/2015	Contractor's Rework and Damages Liability	0	0	0
CORPORATE GOVERNANCE AND FINANCE AUDITS				
2014-15024 09/09/2015	TVA Employee Overtime	$0	$0	$0
2015-15307 09/28/2015	TVA Executive Incentives	0	0	0
OPERATIONAL AUDITS				
2015-15295 06/01/2015	Agreed-Upon Procedures to Verify TVA's Compliance with the Green Pricing Accreditation Program Requirements for Calendar Year 2014	$0	$0	$0
2014-15078 06/25/2015	Effectiveness of TVA's Process to Address Nuclear Emerging Regulatory Issues	0	0	0
2014-15234 06/25/2015	TVA's Talent Acquisition and Deployment Process	0	0	0
2014-15242 09/29/2015	TVA Contractor Workforce Management	0	0	0
2014-15080 09/30/2015	Integrated Resource Planning Process	0	0	0
2014-15224 09/30/2015	Obtaining Things of Value	0	0	0

OIG AUDIT REPORTS • Issued During the Six-Month Period Ended September 30, 2015 (CONTINUED)

Report Number and Date	Title	Questioned Costs	Unsupported Costs	Funds Put To Better Use
INFORMATION TECHNOLOGY AUDITS				
2014-15211 04/09/2015	COMTRAC Implementation	$0	$0	$0
2014-15063-01 06/04/2015	Information Technology Organizational Effectiveness – Enterprise Information Security and Policy	0	0	0
2015-15292 06/25/2015	Electronic Communication by the TVA Board of Directors	0	0	0
2014-15063-02 08/04/2015	Information Technology Organizational Effectiveness – Enterprise Architecture and Programs	0	0	0
2015-15279 08/19/2015	Area Access Manager	0	0	0
2014-15063-03 09/03/2015	Information Technology Organizational Effectiveness – Operations Solutions Delivery	0	0	0
2014-15062 09/10/2015	Maximo 7.5 Upgrade	0	0	0
2014-15063-04 09/22/2015	Information Technology Organizational Effectiveness – Enterprise Customer Operations	0	0	0
TOTAL AUDITS (22)		$7,598,913	$0	$2,106,300

OIG EVALUATION REPORTS • Issued During the Six-Month Period Ended September 30, 2015

Report Number and Date	Title	Questioned Costs	Unsupported Costs	Funds Put To Better Use
2015-15269 07/16/2015	Transmission Fire Protection	$ 0	$ 0	$ 0
2015-15265 07/24/2015	Hydro Generation Obsolete Equipment	0	0	0
2015-15271 07/24/2015	Firearms and Ammunition	0	0	0
2015-15273 07/24/2015	Nuclear Outage Performance	0	0	0
2015-15294 07/24/2015	Hydro Generation Fire Protection	0	0	0
2015-15272 09/29/2015	Significant Changes in TVA Dispatch Cost Compendium	0	0	0
TOTAL EVALUATIONS (6)		$ 0	$ 0	$ 0

Note: A summary of or link to the full report may be found on the OIG's Web site at www.oig.tva.gov.

TABLE I • TOTAL QUESTIONED AND UNSUPPORTED COSTS • AUDITS

Audit Reports	Number of Reports	Questioned Costs	Unsupported Costs
A. For which no management decision has been made by the commencement of the period	0	$0	$0
B. Which were issued during the reporting period	2	$7,598,913	$0
Subtotal (A+B)	2	$7,598,913	$0
C. For which a management decision was made during the reporting period	2[1]	$7,598,913	$0
1. Dollar value of disallowed costs	2	$2,156,279	$0
2. Dollar value of costs not disallowed	1	$5,442,634	$0
D. For which no management decision has been made by the end of the reporting period	0	$0	$0

TABLE I • TOTAL QUESTIONED AND UNSUPPORTED COSTS • EVALUATIONS

Evaluation Reports	Number of Reports	Questioned Costs	Unsupported Costs
A. For which no management decision has been made by the commencement of the period	0	$0	$0
B. Which were issued during the reporting period	0	$0	$0
Subtotal (A+B)	0	$0	$0
C. For which a management decision was made during the reporting period	0	$0	$0
1. Dollar value of disallowed costs	0	$0	$0
2. Dollar value of costs not disallowed	0	$0	$0
D. For which no management decision has been made by the end of the reporting period	0	$0	$0

[1] The total number of reports for which a management decision was made during the period differs from the sum of C(1) and C(2) when the same report includes both recommendations agreed to by management and others not agreed to by management.

TABLE II • FUNDS TO BE PUT TO BETTER USE • AUDITS

Audit Reports	Number of Reports	Funds To Be Put To Better Use
A. For which no management decision has been made by the commencement of the period	1	$1,067,000
B. Which were issued during the reporting period	1	$2,106,300
Subtotal (A+B)	2	$3,173,300
C. For which a management decision was made during the reporting period	1	$1,067,000
1. Dollar value of recommendations agreed to by management	1	$1,067,000
2. Dollar value of recommendations not agreed to by management	0	$0
D. For which no management decision has been made by the end of the reporting period	1	$2,106,300

TABLE II • FUNDS TO BE PUT TO BETTER USE • EVALUATIONS

Evaluation Reports	Number of Reports	Funds To Be Put To Better Use
A. For which no management decision has been made by the commencement of the period	0	$0
B. Which were issued during the reporting period	0	$0
Subtotal (A+B)	0	$0
C. For which a management decision was made during the reporting period	0	$0
1. Dollar value of recommendations agreed to by management	0	$0
2. Dollar value of recommendations not agreed to by management	0	$0
D. For which no management decision has been made by the end of the reporting period	0	$0

APPENDIX 4

AUDIT AND EVALUATION REPORTS WITH CORRECTIVE ACTIONS PENDING

As of the end of the semiannual period, final corrective actions associated with 11 audits and 11 evaluations/inspections reported in previous semiannual reports were not completed. Presented below for each audit and evaluation are the report number, date, and a brief description of final actions planned to resolve the open recommendations, including the date management expects to complete final action.

Audit Report Number and Date	Report Title and Recommendation(s) for Which Final Action is Not Complete
2010-13132 06/15/2011	**Physical and Logical Access for Contractors** TVA agreed to create a matrix to cross-reference TVA roles to assets and identify the associated qualification and background requirements needed to gain access to that asset and develop a process to restrict contractor access to sensitive data and assets until the proper clearances have been obtained. Management expects to complete final action by June 30, 2016.
2012-14567 01/30/2013	**Building and Infrastructure Failure Risks** TVA agreed to enhance Tririga functionality and other tools for building asset information and address weaknesses in the Tririga production database. Management expects to complete final action by December 31, 2015.
2013-15104 02/12/2014	**PowerWAN Security and Architecture** TVA Management agreed to develop policies and practices to ensure legitimate traffic is traversing the PowerWAN network. Management expects to complete final action by April 1, 2016.
2013-14959 08/07/2014	**TVA Environmental Risk Management** TVA Environment and Energy Policy group will update TVA's Environmental Management System to better describe environmental review processes and responsibilities. Management expects to complete final action by September 30, 2017.
2014-15036 09/03/2014	**Bartlett Holdings, Inc. – Bechtel Power Corporation Subcontract** TVA agreed to recover $1,484,582 in questioned payroll tax and insurance costs and related fee; $60,287 in ineligible costs for an employee who did not maintain a permanent residence more than 60 miles from his assigned workplace; and $2,565 in ineligible labor costs and fee. Management expects to complete final action by March 31, 2016.
2014-15065 09/23/2014	**Network Security Zones and Perimeter Architecture** TVA agreed to design a new cable plant system and install new conduit and cables. Management expects to complete final action by March 18, 2016.
2014-15037 11/17/2014	**Bechtel Power Corporation** TVA agreed to recover $923,231 in overbilled labor and related costs; $938,928 in ineligible or unsupported relocation, permanent and temporary assignment and travel costs; and $204,336 in ineligible or unsupported affiliate company and subcontractor costs. Management expects to complete final action by March 31, 2016.
2014-15044 11/19/2014	**Nexant, Inc.** TVA agreed to pursue recovery of $269,009 in excessive labor costs; $144,570 in ineligible labor costs; $18,267 in ineligible employee travel costs; and $67,189 in ineligible incentive costs, of which, to date, TVA has recovered $15,685. Management expects to complete final action by November 19, 2015.

AUDIT AND EVALUATION REPORTS WITH CORRECTIVE ACTIONS PENDING (continued)

Audit Report Number and Date	Report Title and Recommendation(s) for Which Final Action is Not Complete
2014-15059 01/13/2015	**2014 Federal Information Security Management Act** TVA agreed to implement Interconnection Service Agreements (ISA) for each contractor system as appropriate and document justifications for systems that have not implemented ISAs. TVA agreed to update or create procedures as appropriate to address the program for training users who have been designated as having significant security responsibilities. TVA also agreed to document the FIPS 199 rating of systems and maintain documentation of the System Security Plan or status for those systems, including controls selected, system role holders, and projected dates for system authorization completion. TVA agreed, where appropriate, to document and implement a Continuous Monitoring Plan for the system. Finally, TVA agreed to generate remediation tickets to the appropriate responsible parties for addressing deviations. Quarterly tickets will be generated for Compute, Network, and Database areas to review vulnerability and baseline configurations deviations. Tasks will then be added to remediate or accept any deviations found. TVA agreed to also update TVA-SPP-12.04, TVA Cyber Security Patch & Vulnerability Management Program, to clarify Time to Remediate and define expectations for remediation. Management expects to complete final action by December 11, 2015.
2014-15060 02/19/2015	**Biennial Review – Use and Protection of Personally Identifiable Information** TVA agreed to (1) modify policy and automate annual access review by managers, who will also conduct periodic clean desk reviews and report findings to the privacy office; (2) review systems containing restricted personally identifiable information (RPII) and make necessary classification changes and track the disposition of RPII surveys and document resolution; and (3) align training for information owners and privacy system security officers with other ongoing training efforts. Management expects to complete final action by February 29, 2016.
2015-15278 03/05/2015	**Contractor Rate Review** TVA agreed to negotiate fringe benefits which more accurately reflect the contractor's actual historical costs, use the Hourly Craft Superintendent classification provided for in TVA's labor agreements as a lower cost option, when available, and seek recovery of any over-billed charges. Management expects to complete final action by March 4, 2016.

Evaluation Report Number and Date	Report Title and Recommendation(s) for Which Final Action is Not Complete
2012-14535 03/21/2013	**Master Key Program Management – Energy Delivery** TVA agreed to secure facilities protected by master keys to minimize the risk posed by keys outside TVA's control and develop specifications for the purchase of a new system. A contract has been awarded and management expects to complete final action by June 30, 2017.
2012-14636 08/28/2013	**Master Key Program Management – Property & Natural Resources** TVA agreed to develop standard policies and procedures. Management expects to complete final action by October 15, 2015.
2013-14950 09/19/2013	**TVA's Succession Planning** TVA management agreed to (1) continue to evaluate ways to improve cross-pollination using a system to reduce preparation time and plan to submit a proposal for a new system during fiscal year 2016 business planning, and (2) identify critical executive positions. Management expects to complete final action by September 30, 2016.
2012-14587 10/17/2013	**Nuclear Power Group and Coal and Gas Operations Critical Spare Parts Program** TVA agreed to (1) develop the appropriate procedures to define the roles, responsibilities, and accountabilities of key persons, and define the decision and approval process in regard to the procurement of critical spares; (2) define maintenance program accountabilities for inventory including critical spares; (3) take steps to follow up on actions recommended by the management consulting firm; and (4) define the decision and approval process for the removal of the critical spare designation from spare parts in inventory. Management expects to complete final action by November 5, 2015.

AUDIT AND EVALUATION REPORTS WITH CORRECTIVE ACTIONS PENDING (continued)

Evaluation Report Number and Date	Report Title and Recommendations for which Final Action is Not Complete
2013-15157 06/05/2014	**Actions to Address River Operations Systems and Components with Poor Ratings** TVA agreed to develop a 10-year asset management plan to further document risks and develop a long-term strategy for addressing major components with poor ratings across the non-nuclear fleet. Management expects to complete final action by September 30, 2016.
2013-15135 07/30/2014	**Actions to Address Coal Plant Systems and Programs with Poor Ratings** TVA agreed to (1) document justification when actions are not taken to address systems and programs with red and yellow ratings, (2) reinforce the importance of consistent documentation of system health reports, and (3) consider the potential impact of eliminating the requirement to do asset health assessments on TVA's non-nuclear asset condition risk and determine a schedule for completing health assessments that will adequately mitigate the risk of equipment failure. Management expects to complete final action by March 31, 2016.
2014-15056 09/25/2014	**Nuclear Groundwater Review** TVA agreed to form a groundwater working group with representatives from all sites to address outstanding program weaknesses. Management expects to complete final action by September 30, 2016.
2014-15053 09/29/2014	**Coal Plant Preventive Maintenance** TVA agreed to (1) increase preventive maintenance (PM) completion and reduce deviations from PM schedules and reinforce the importance of PM activities, (2) develop a way to more accurately capture and report PM compliance and other appropriate PM tracking metrics, (3) expedite maintenance basis optimization efforts, and (4) consider the potential impact of having PM governed only by guidelines and not requirements. Management expects to complete final action by April 15, 2016.
2014-15216 09/29/2014	**Follow-Up Review of Coal Fire Protection** TVA agreed to prioritize impairments and establish a due date for long-term fire impairments or make a formal decision to not pursue repair; train employees on work management priorities for fire impairments; track high-priority fire impairments to resolution using a monthly scorecard; revise policies and procedures (Standard Programs and Processes [SPP]) to allow a formal non-conformance process; take inventory to determine baseline equipment status; revise SPPs to include a standard equipment list and develop an action plan to replace or purchase needed equipment to fill gaps; revise SPPs to require a Problem Evaluation Report when minimum staffing is not met; revise SPPs to require capturing and sharing of lessons learned for all fires; and revise SPPs to include a new rating calculation and process for sharing assessment data with Power Operations senior leadership. Management expects to complete final action by December 31, 2016.
2012-14882 09/30/2014	**Injury Reporting at TVA** TVA agreed to improve the reporting of injuries including establishment of a process for reconciling Form 1444 to Form 17719. Additionally, TVA agreed to evaluate the potential influence of the corporate multiplier on the reporting of recordable injuries. Management expects to complete final action by March 31, 2016.
2014-15048 12/22/2014	**Natural Gas Monitoring** Fuel Accounting agreed to contact the vendor for the return of money due. Management expects to complete final action by October 16, 2015.

INVESTIGATIVE REFERRALS AND PROSECUTIVE RESULTS[1]

Referrals	
Subjects Referred to U.S. Attorneys	**18**
Subjects Referred to State/Local Authorities	**2**
Results	
Subject Indicted/Information Filed	**1**
Subjects Convicted	**1**
Pretrial Diversion	**0**
Federal Referrals Declined	**14**
State Referrals Declined	**0**

[1] These numbers include task force activities and joint investigations with other agencies.

APPENDIX 6

HIGHLIGHTS – STATISTICS

	SEPT 30, 2015	MAR 31, 2015	SEPT 30, 2014	MAR 31, 2014	SEPT 30, 2013
AUDITS					
AUDIT STATISTICS					
Carried Forward	28	28	24	28	38
Started	21	11	20	17	21
Canceled	(1)	(0)	(1)	(1)	(1)
Completed	(22)	(11)	(15)	(20)	(30)
In Progress at End of Reporting Period	26	28	28	24	28
AUDIT RESULTS (Thousands)					
Questioned Costs	$7,599	$8,908	$2,612	$635	$2,916
Disallowed by TVA	$2,156	$8,908	$2,612	$308	$647
Recovered by TVA	$2,981	$89	$484	$164	$2,447
Funds to Be Put to Better Use	$2,106	$1,067	$512	$9,584	$36,522
Agreed to by TVA	$1,067	$512	$414	$20,938	$23,100
Realized by TVA	$142	$7,375	$13,114	$375	$2,479
OTHER AUDIT-RELATED PROJECTS					
Completed	7	5	10	5	5
Cost Savings Identified/Realized (Thousands)	$0	$0	$0	$0	$0
EVALUATIONS					
Completed	6	1	10	3	6
Cost Savings Identified/Realized (Thousands)	$0	$0	$0	$0	$0
INVESTIGATIONS[1]					
INVESTIGATION CASELOAD					
Opened	126	126	134	112	173
Closed	142	146	123	148	158
In Progress at End of Reporting Period	134	152	163	150	179
INVESTIGATIVE RESULTS (Thousands)					
Recoveries	$1,064.0	$522.2	$89.1[2]	$10,874.7[3]	$899.9
Savings/Projected Savings	$1,897.1	$403.3	$125.0	$0	$550.4
Fines/Penalties/Fees	$64.1	$0.2	$0.8	$1	$603.8
Other Monetary Loss	$0	$0	$0	$0	$519.3
MANAGEMENT ACTIONS					
Disciplinary Actions Taken (Number of Subjects)	14	10	14	22	18
Counseling/Management Techniques Employed (Number of Cases)	9	17	11	14	20
Debarment	3	0	0	0	0
PROSECUTIVE ACTIVITIES (Number of Subjects)					
Referred to U.S. Attorneys	18	8	16	14	18
Referred to State/Local Authorities	2	0	0	2	0
Indicted/Information Filed	1	6	0	5	0
Convicted	1	6	0	1	2
Pretrial Diversion	0	0	0	1	0

[1] These numbers include task force activities and joint investigations with other agencies.
[2] $12,573 of this amount is restitution ordered to be paid to a nongovernmental financial institution as the result of a criminal investigation.
[3] $10,794,728 of this total is restitution ordered in a TVA OIG led federal criminal case. The defendant was ordered to repay victims of a Ponzi scheme, the largest portion of which was comprised of his fraudulent collection of money from Valleywide investors under the pretense that they were helping fund the Kingston ash spill remediation.

GOVERNMENT CONTRACTOR AUDIT FINDINGS

The National Defense Authorization Act for Fiscal Year 2008, P.L. 110-181, requires each Inspector General appointed under the Inspector General Act of 1978 to submit an appendix on final, completed contract audit reports issued to the contracting activity that contain significant audit findings—unsupported, questioned, or disallowed costs in an amount in excess of $10 million, or other significant findings—as part of the Semiannual Report to Congress. During this reporting period, the Office of the Inspector General issued no contract review reports under this requirement.

APPENDIX 8

PEER REVIEWS OF THE TVA OIG

Audits Peer Review

IG audit organizations are required to undergo an external peer review of their system of quality control at least once every three years, based on requirements in the *Government Auditing Standards.* Federal audit organizations can receive a rating of pass, pass with deficiencies, or fail. TVA OIG underwent its most recent peer review of its audit organization for the period ended September 30, 2013. The review was performed by the Special Inspector General for the Troubled Asset Relief Program (SIGTARP). The SIGTARP issued the report, dated March 31, 2014, in which it concluded the TVA OIG audit organization's system of quality control for the fiscal year ended September 30, 2013, was suitably designed and complied with to provide the OIG with reasonable assurance of performing and reporting in conformity with applicable professional auditing standards in all material respects. Accordingly, the TVA OIG received a rating of pass. The peer review report is posted on our Web site at http://www.oig.tva.gov/PDF/PeerReviewReport03312014.

Investigations Peer Review

Investigative operations undergo an external peer review, Quality Assessment Review (QAR), at least once every three years. The United States Department of Commerce OIG conducted a QAR of the TVA OIG Investigative Operations. The Commerce OIG found the "…system of internal safeguards and management procedures for the investigative function of the Office of the Inspector General for the Tennessee Valley Authority in effect for the year ended April 30, 2013, is in compliance with the quality standards established by CIGIE and the applicable Attorney General guidelines. These safeguards and procedures provide reasonable assurance of conforming with professional standards in the planning, execution and reporting of its investigations." The QAR report can be found on our Web site at http://oig.tva.gov/PDF/22NOV2013-tvaoig-inv-peer-review.pdf.

APPENDIX 9

PEER REVIEW OF INVESTIGATIVE OPERATIONS, U.S. DEPARTMENT OF STATE AND BROADCASTING BOARD OF GOVERNORS OFFICE OF THE INSPECTOR GENERAL

The TVA OIG completed a peer review of Investigative Operations, U.S. Department of State and Broadcasting Board of Governors Office of the Inspector General (DOS OIG) during this semiannual period. We issued our final report to DOS OIG on April 20, 2015. We reviewed the organization's internal safeguards and management procedures in effect for the annual period ending January 31, 2015, and found the organization in full compliance with the quality standards established by the Council of the Inspectors General on Integrity and Efficiency and applicable Attorney General Guidelines.

GLOSSARY

Disallowed Cost
A questioned cost that management, in a management decision, has sustained or agreed should not be charged to the agency.

Final Action
The completion of all management actions, as described in a management decision, with respect to audit findings and recommendations. When management concludes no action is necessary, final action occurs when a management decision is made.

Funds Put To Better Use
Funds which the OIG has disclosed in an audit report that could be used more efficiently by reducing outlays, deobligating program or operational funds, avoiding unnecessary expenditures, or taking other efficiency measures.

Improper Payment
Any payment that should not have been made or was made in an incorrect amount under statutory, contractual, administrative, or other legally applicable requirements, as defined in the Improper Payments Improvement Act.

Management Decision
Evaluation by management of the audit findings and recommendations and the issuance of a final decision by management concerning its response to such findings and recommendations.

Questioned Cost
A cost the IG questions because (1) of an alleged violation of a law, regulation, contract, cooperative agreement, or other document governing the expenditure of funds; (2) such cost is not supported by adequate documentation; or (3) the expenditure of funds for the intended purposes was unnecessary or unreasonable.

Unsupported Costs
A cost that is questioned because of the lack of adequate documentation at the time of the audit.

ABBREVIATIONS & ACRONYMS

The following are acronyms and abbreviations widely used in this report.

AIGI	Assistant Inspector General Investigations
Blackberry	The Cove at Blackberry Ridge, LLC
Board	TVA Board of Directors
CIGIE	Council of the Inspectors General on Integrity and Efficiency
CO	Contracting Officer
CRS	Center for Resource Solutions
CWM	Contractor Workforce Management
DOS OIG	U.S. Department of State and Broadcasting Board of Governors Office of the Inspector General
EAIP	Executive Annual Incentive Plan
EAM	Enterprise Asset Management
ECIE	Executive Council on Integrity and Efficiency
ELTIP	Executive Long-Term Incentive Plan
EPU	Extended Power Uprate
ERI	Emerging Regulatory Issues
ERM	Enterprise Risk Management
ESCO	Energy Services Company
FBI	Federal Bureau of Investigation
FECA	Federal Employees Compensation Act
FIA	Field Invoice Approver
FISMA	Federal Information Security Management Act
FY	Fiscal Year
GAO	Government Accountability Office
Habitat	Habitat for Humanity
HR	Human Resources
HRT	Highland Ridge Tower
IG	Inspector General
IRP	Integrated Resource Plan
ISA	Interconnection Service Agreements
IT	Information Technology
IT1K	1,000 Days to Success
ITSA	IT Security Assessment
KCSO	Knox County Sheriff's Office
Kinder Morgan	Kinder Morgan Limited Partnership
NPG	Nuclear Power Group
NRC	Nuclear Regulatory Commission
OIG	Office of the Inspector General
OPM	Office of Personnel Management
PCIE	President's Council on Integrity and Efficiency
PD	Police Department
PER	Problem Evaluation Reports
PM	Preventive Maintenance
Protocol	Obtaining Things of Value from TVA Protocol
QAR	Quality Assessment Review
RPII	Restricted Personally Identifiable Information
Second Harvest	Second Harvest Food Bank
SEIS	Supplemental Environmental Impact Statement
SIGTARP	Special Inspector General for the Troubled Asset Relief Program

The following are acronyms and abbreviations widely used in this report. (continued)

SPP	Standard Programs and Processes
SWCI	Stone & Webster Construction, Inc.
TVA	Tennessee Valley Authority
TVAP	TVA Police
TVAP&EM	TVA Police and Emergency Management
U.S.	United States of America
UTPD	The University of Tennessee Police Department
WBN	Watts Bar Nuclear Plant

OFFICE** of the **INSPECTOR GENERAL

400 West Summit Hill Drive
Knoxville, Tennessee 37902

The OIG is an independent organization charged with conducting audits, evaluations, and investigations relating to TVA programs and operations, while keeping the TVA Board and Congress fully and currently informed about problems and deficiencies relating to the administration of such programs and operations.

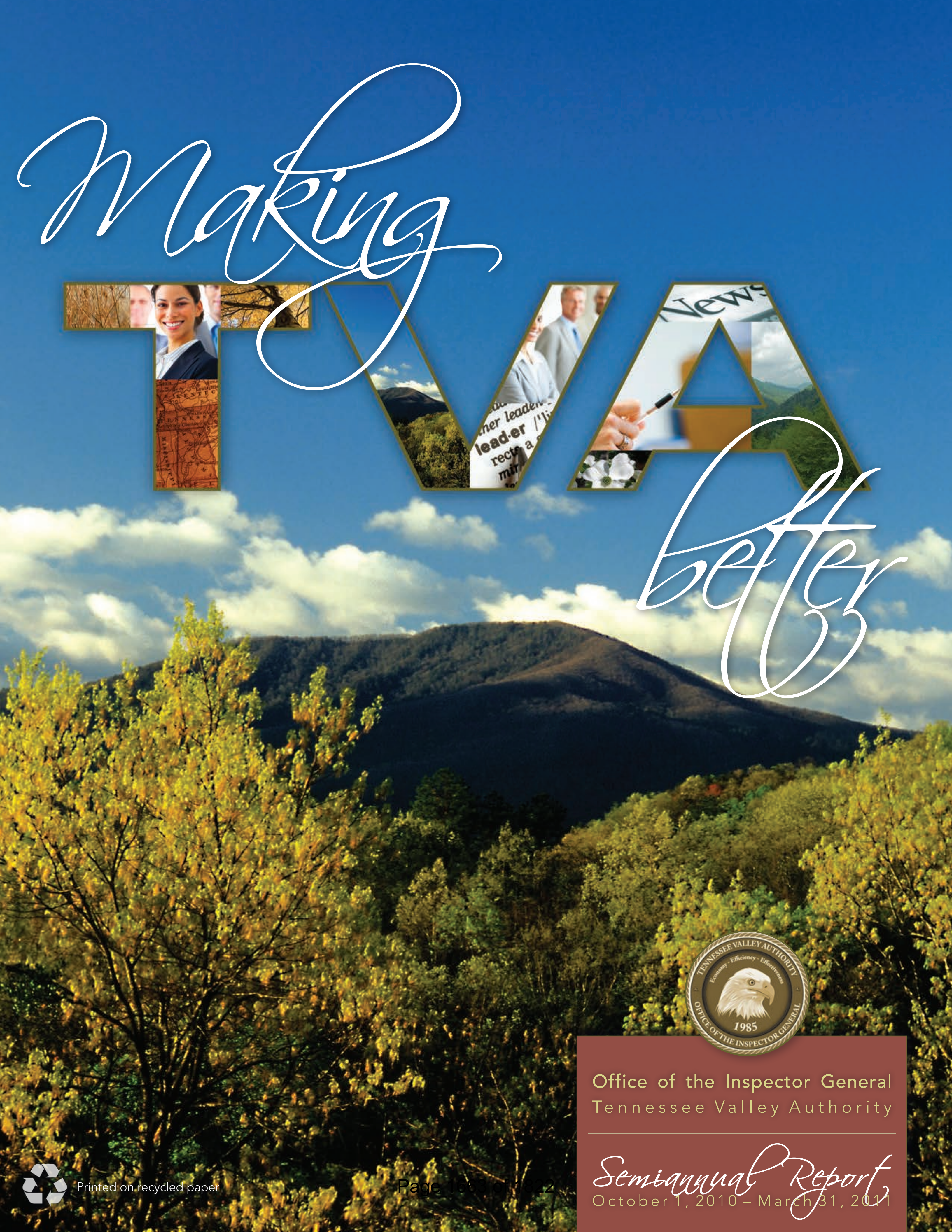
The OIG focuses on (1) making TVA's programs and operations more effective and efficient; (2) preventing, identifying, and eliminating waste, fraud, and abuse and violations of laws, rules, or regulations; and (3) promoting integrity in financial reporting.

If you would like to report to the OIG any concerns about fraud, waste, or abuse involving TVA programs or violations of TVA's Code of Conduct, you should contact the OIG EmPowerline system. The EmPowerline is administered by a third-party contractor and can be reached 24 hours a day, seven days a week, either by a toll-free phone call (1-855-882-8585) or over the Web (www.oigempowerline.com). You may report your concerns anonymously or you may request confidentiality.

Report Concerns to the OIG Empowerline

Office of the Inspector General
TENNESSEE VALLEY AUTHORITY
Semiannual Report
April 1, 2015 - September 30, 2015

Making TVA better



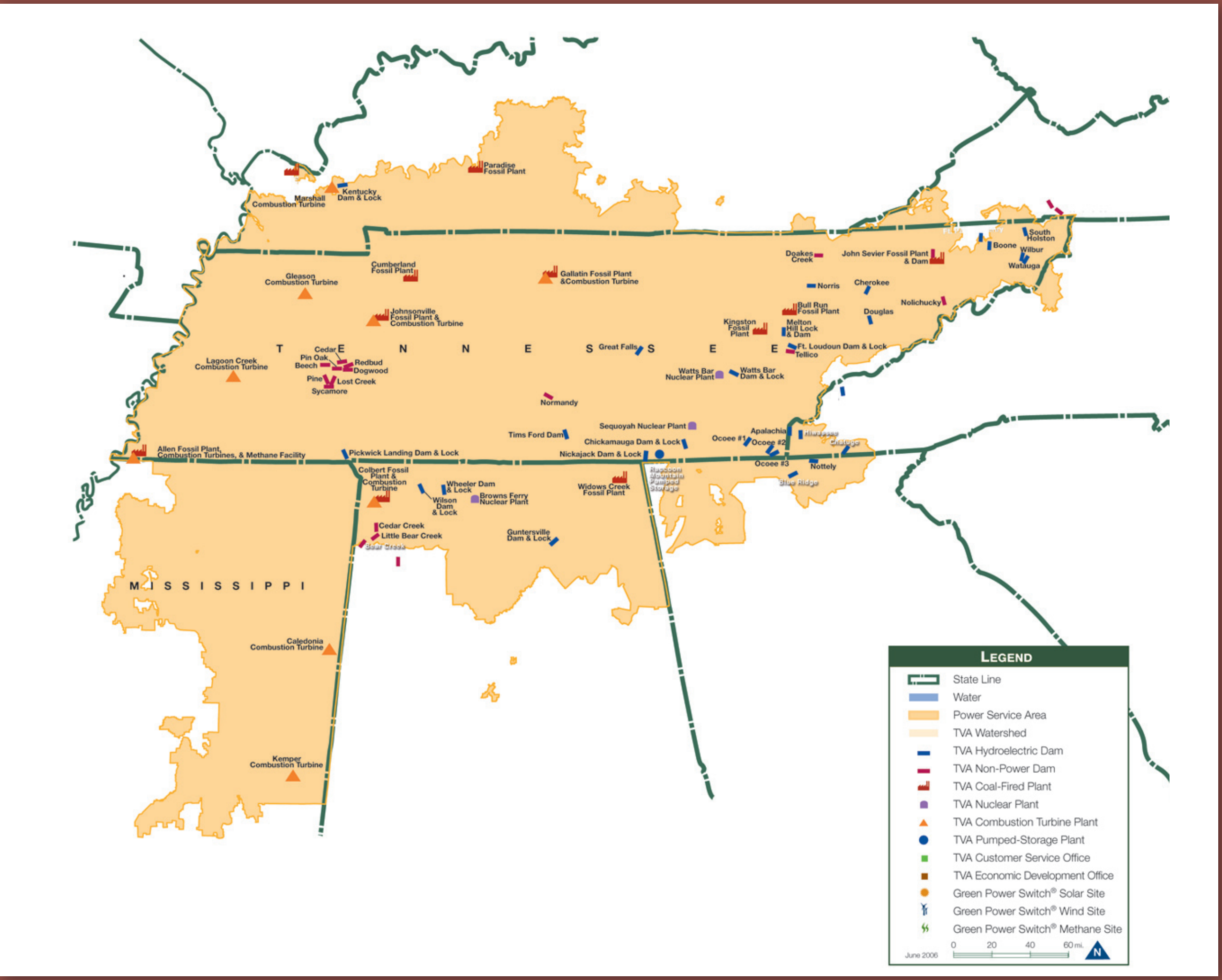
Office of the Inspector General

Tennessee Valley Authority

Semiannual Report

October 1, 2010 – March 31, 2011

Printed on recycled paper



TVA Power Generation 2010

(in millions of kilowatt hours)

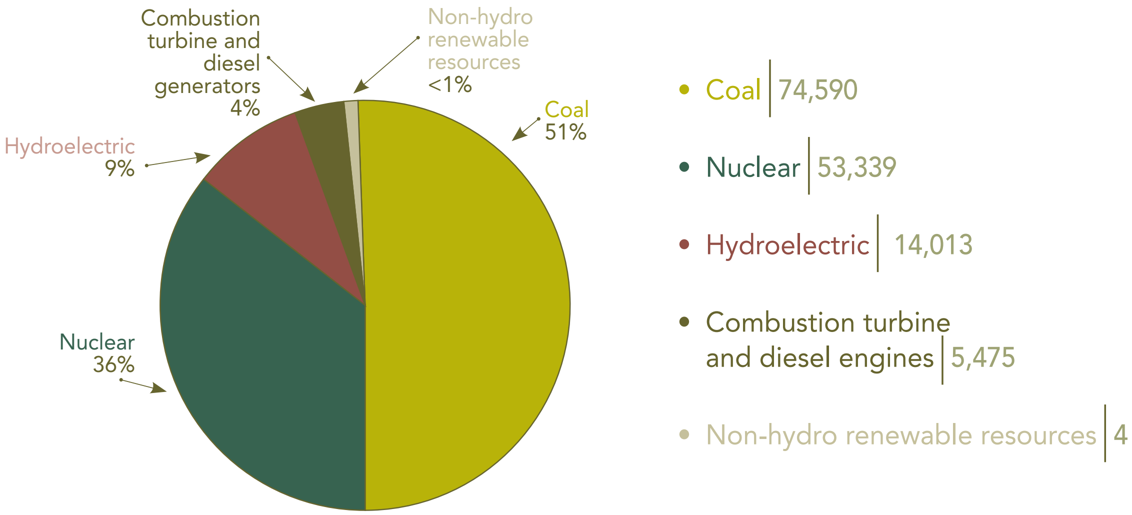


Table of Contents

Message From The Inspector General

making **TVA** *better*

Message from the Inspector General

I am pleased to present our report for the period October 1, 2010, through March 31, 2011. The theme of this semiannual is "Making TVA Better." As you will see throughout this report, the TVA OIG employees are working hard to do just that. In this semiannual period, our audit, inspection, and investigation activities resulted in almost $35 million in recoveries, fines/penalties, potential savings, questioned costs, and funds which could be put to better use, as well as numerous recommendations to help TVA become better.

Richard W. Moore
Inspector General

Some of the highlights include:

- Almost $25 million of potential savings opportunities for TVA to use in negotiations of contracts associated with work primarily at TVA's Bellefonte Nuclear Plant as a result of our preaward audits.
- The first debarment of a TVA contractor and institution of a formal process for suspension and debarment as a result of an OIG criminal investigation.
- A follow-up audit to our 2006 review of TVA's Role as a Regulator which highlighted TVA has made slow progress in designing a program to enable TVA to fulfill its regulatory responsibilities.
- An inspection of the Kingston ash spill stability assessment process which showed TVA has taken actions to improve ash management governance, drive culture change, and evaluate stability and safety surrounding ash impoundments. We will continue to monitor TVA's actions in this area as this is a long-term project that must continue to be a priority.

Making TVA better is a purpose we share with TVA management and the Board. Accomplishing this purpose depends, in part, on creating and maintaining a healthy relationship. Disagreements will occur. It is how we communicate and discuss issues that will determine in large part how effective all of us will be in making TVA better. The OIG and, we believe, TVA are committed to having mutually respectful dialogue on the tough issues.

I would like to thank Congress, the TVA Board, and TVA management for their continued support of our work. We look forward to continuing to do our part to make TVA better.

TENNESSEE VALLEY AUTHORITY · Economy · Efficiency · Effectiveness · 1985 · OFFICE OF THE INSPECTOR GENERAL

The Role of the OIG:

making TVA *better*

SPECIAL FEATURE

The Role of the OIG: Making TVA Better

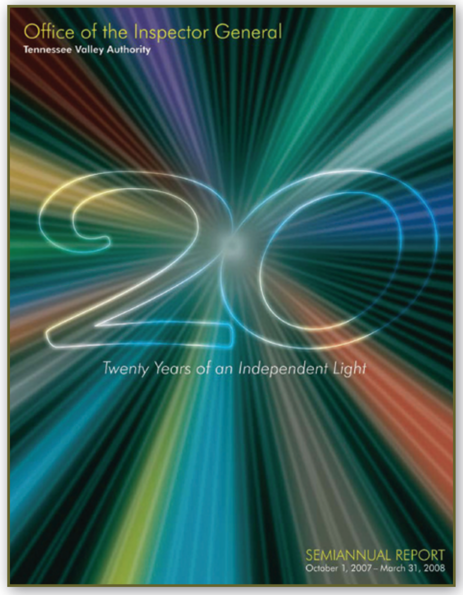
Why we do what we do *In 1993, Professor Paul C. Light's seminal work, Inspectors General and the Search for Accountability, quickly became the authoritative source on the work of Inspectors General (IGs). Light traced the origins of the federal IG concept and the sometimes unrealistic expectations placed on IGs to "clean up government." Congress expanded the number and size of the various Offices of Inspector General (OIGs) in the late 1970s and into the 1980s in response to a series of scandals in federal agencies.*

As Paul Light explains, the Inspector General Act of 1978 was designed to do basically four things: (1) consolidate the scattered audit and investigation divisions into an IG office for each federal agency; (2) ensure a measure of independence by putting presidential appointees into the IG jobs; (3) give the IGs wide latitude in the scope of their work and in how to organize their offices; and (4) provide greater resources for the war on fraud, waste, and abuse.

According to Light, the effectiveness of the IG concept should be measured in terms of the "quality of life produced by the government." Whether a better quality of life was being ushered in by the IGs could be addressed by asking these four questions: (1) Is anyone listening? (2) Is the public more trusting? (3) Is the government less vulnerable to fraud, waste, and abuse? and, (4) Is the government producing outcomes of greater public value? Light concluded that at least back in the early 1990s the results were mixed.

With all due respect to Professor Light, those inquiries seem to impute far more power than IGs actually enjoy. IGs should be able to "move the needle" on the metrics that count in government, but much of the final results lie outside the scope of an IG's work. Light recognized that measuring the effectiveness of OIGs is indeed tricky. Raw statistics rarely tell the whole tale.

For the TVA OIG, we have settled on a straightforward mission of "making TVA better." We, like all federal IGs, report our work in more complex metrics established by the IG Act which include terms such as, "funds put to better use" and "questioned and unsupported costs." See Appendices 2-6 on pages 44-50 for statistical information. Ultimately, however, Professor Light's conclusion that the work of an OIG should make life better for people seems right. For us, that means our work should improve the quality of life for the residents of the Tennessee Valley. It's a matter of public trust.



What we did that makes a difference

Occasionally, as we did in our March 2008 semiannual report – ***Twenty Years of an Independent Light***, we offer our stakeholders our perspective on what the TVA OIG is doing that makes a difference. We offer the traditional statistical data common to our work, but we go beyond that. The reviews we discuss here, for the most part, do not represent huge financial savings for TVA in terms of its annual operating costs. They do illustrate how our

work improves the quality of life for residents of the Tennessee Valley.

The OIG initiated a first in TVA history; the debarment of a contractor doing business with TVA. In October 2010, TVA debarred Holtec International, Inc., based on the results of a criminal investigation conducted by the OIG. Because of our recommendation, TVA created a formal suspension and debarment process and proceeded to debar Holtec for 60 days. Holtec agreed to pay a $2 million administrative fee and submit to independent monitoring of its operations for one year. The TVA Board's Audit, Risk, and Regulation Committee and TVA management fully supported the OIG's recommendation to create a suspension and debarment process and submit Holtec to that process. TVA's Supply Chain organization and Office of General Counsel worked collaboratively with the OIG to achieve this milestone in TVA history.

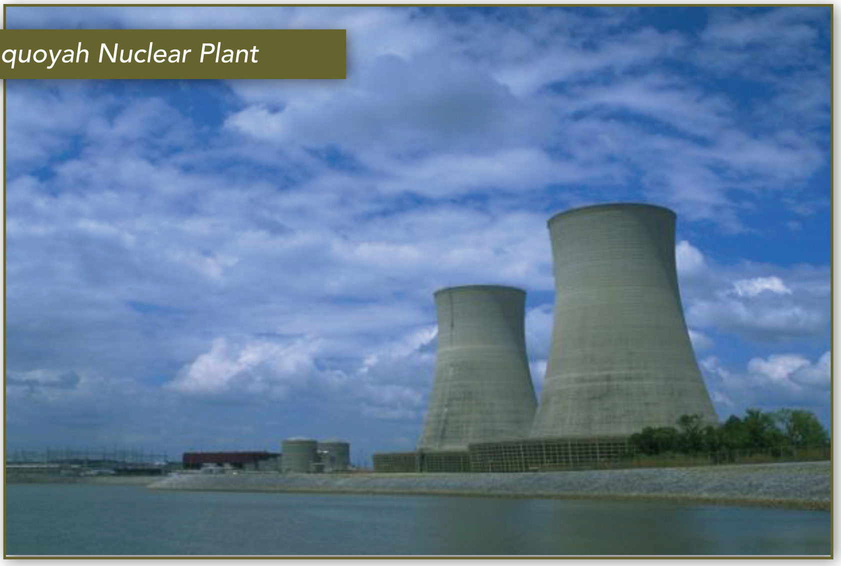
How does one contractor being debarred make life better for Valley residents? Ultimately, the less vulnerable TVA is to fraud the better chance rates stay low. This debarment signaled TVA's commitment to do more than simply ask for the money back. This debarment action was literally heard around the world and drew a line in the sand. Yes, much of this was symbolic, but symbols matter when you are the largest public power company in America.

Another example of the TVA OIG adding value is our work in examining TVA's status as an electric rate regulator. TVA wholesales power to 155 distributors across the Tennessee Valley. The TVA Act makes TVA the regulator of those distributors through power contracts that contain terms designed to basically provide fairness in the way distributors provide power to the end use customer. In 2006, the OIG issued a report that essentially questioned whether TVA was fulfilling its responsibility as a regulator of the distributors. This semiannual period, we looked once again at this issue. We completed our report entitled, "Follow-up Review of TVA's Role as a Regulator—Use of Electric System Revenues for Nonelectric Purposes," to check the progress of TVA management's efforts to improve oversight of its distributors.

This particular review illustrates the limited power of the OIG. We can make recommendations, but we have no power to make TVA follow these recommendations. In the case of our original report, "TVA's Role as a Regulator," issued in June 2006, there has been an interminable delay in TVA management's resolution of the issues we raised. This delay is in part due to the fact that for too long TVA has neglected its regulatory responsibilities and correcting that pattern is now complicated. Since our first role as a regulator report, we initiated audits of the distributors in 2008. Our audits identify instances of noncompliance with the power contracts and weaknesses in TVA's role as a regulator that should be identified by management in its process to govern and regulate the distributors. Our distributor reviews are on-going and provide Valley residents with some measure of confidence that there are independent reviews being conducted of those distributors. To TVA management's credit, there has been steady progress to design a program that will enable TVA to fulfill its responsibilities as a regulator. We are hopeful that a renewed commitment to fulfill statutory responsibilities will make TVA better and ultimately life in the Valley better.

Finally, we would offer our Kingston work as another example of how we

Sequoyah Nuclear Plant




Kingston Fossil Plant

make TVA better. In the aftermath of the Kingston coal ash spill of December 2008, TVA set about to "make things right." Our independent assessment of TVA's remediation work verified that they did. We engaged Marshall Miller and Associates, Inc., (Marshall Miller) to provide the TVA OIG expert advice on whether TVA has taken appropriate steps to stabilize its coal ash impoundments and to appropriately address the risks associated with all of their coal ash processes. Given the reputational harm caused by the Kingston coal ash spill, TVA's credibility was impaired and an independent review of their progress was essential.

Our reports on the remediation work of TVA in the aftermath of the Kingston coal ash spill provides documented evidence that TVA fulfilled its promise to "make things right." That is not to say that everything was done perfectly or that all of TVA's critics are happy now. What we have said is that our independent engineers have satisfied us that what TVA has done meets high standards and exhibits a commitment to aggressively address apparent risks to public safety in a professional way. TVA has made great strides in becoming a "good neighbor" once again.

In the end, the effectiveness of our office depends, in part, on a healthy relationship between the OIG and the federal agency. Given the oft cited difficult dynamics between the "watchdog" and the reviewed agency, trust can be fickle. Naturally, the better the trust is, the better the relationship is and, hence, the better the results are. Mutually respectful communication between TVA and the OIG continues to grow which makes for a better TVA and a better OIG, but more importantly inures to the benefit of the residents of the Tennessee Valley. We recognize and appreciate the efforts made by both the TVA Board and TVA management to contribute to our mutual purpose of making TVA better.

Noteworthy Undertakings

making **TVA** *better*

Noteworthy Undertaking

Audit and Investigation Teams Pass Peer Reviews *All federal IG audit and investigative groups are required by standards to undergo a peer review every three years. These peer reviews are conducted by other OIG offices using guidance provided by Council of the Inspectors General on Integrity and Efficiency (CIGIE) to ensure compliance with applicable standards. During this semiannual period, we are pleased to announce both our Audit and Investigation teams passed their peer reviews.*

Council of the INSPECTORS GENERAL on INTEGRITY and EFFICIENCY

Audits

Our audit organization's peer review was conducted by an ad hoc CIGIE team led by the Department of Education OIG with members from four other OIGs. The peer review team reviewed our audit organization's system of quality control in place to ensure compliance with the ***Government Auditing Standards***. For the period ending September 30, 2010, our audit organization received a pass rating which is the highest rating. Specifically, the peer review report states:

> *The system of quality control for the TVA OIG audit organization in effect for the year ended September 30, 2010, has been suitably designed and complied with to provide TVA OIG with reasonable assurance of performing and reporting in conformity with applicable professional standards in all material respects. Federal audit organizations can receive a rating of pass, pass with deficiencies, or fail. TVA OIG has received a peer review rating of pass.*

Investigations

Our Investigation organization's peer review was conducted by the Office of Personnel Management OIG. The peer review team reviewed our system of internal safeguards and management procedures to ensure conformity with both the ***Quality Standards for Investigations*** (December 2003) and the ***Qualitative Assessment Review Guidelines for Federal Offices of Inspector General*** (May 2009) established by CIGIE, as well as the ***Attorney General Guidelines for Offices of Inspector General with Statutory Law Enforcement Authority*** (December 2003). For the period ending August 1, 2010, the peer review team found:

> *In our opinion, the system of internal safeguards and management procedures for the investigative function of the TVA/OIG in effect for the year ending August 1, 2010, is in compliance with the Quality Standards for Investigations and the Attorney General Guidelines. These safeguards and procedures provide reasonable assurance of conforming with professional standards in the conduct of investigations.*

Executive Overview

making TVA better

Executive Overview

During this semiannual period, we are highlighting – both generally and specifically – how the OIG works to make TVA better by overseeing its operations and making recommendations to enhance and streamline its processes. These functions are in keeping with the primary responsibilities of an IG's office, which are to detect and prevent fraud, waste, abuse, and violations of law as well as to promote economy, efficiency, and effectiveness in federal government operations. Since our establishment in 1985, at the heart of our office's mission has lived the purpose that drives us – to make TVA better. As discussed in the Special Feature, our 2008 semiannual report – Twenty Years of an Independent Light chronicles this history.

As one of 73 IG offices with statutory independence, we have honored this authority by focusing on manifesting a better quality of life for TVA stakeholders. In this semiannual period, our audits, inspections, and investigations have led to TVA recovering or saving almost $35 million. These savings ideally translate into lower electricity rates for TVA customers, which include everyone who uses electricity in the Tennessee Valley. Essentially, the more efficient and effective an IG's office is, the more efficient and effective its beneficiary, in this case TVA, becomes. Below you will see how our office has specifically accomplished our informal mission statement to make TVA better during this semiannual period.

AUDITS

Our Audits team issued 20 audits this semiannual period that identified nearly $5 million in questioned costs, helped TVA to recover close to $.8 million, and identified nearly $25 million that could be put to better use. In addition, these audits identified needed improvements in the areas of power distributor regulation, distributor compliance with contract terms, storage and handling of ammonia, as well as information technology (IT) security and controls.

Contract Audits

To support TVA management in negotiating procurement actions and in support of the nuclear construction program, we completed five preaward audits of cost proposals submitted by companies proposing to provide (1) nondestructive examinations at TVA's Nuclear and Fossil Power generating units, (2) engineering services for work on TVA's Bellefonte Nuclear Plant Unit 1, and (3) geotechnical services. Our audits identified nearly $25 million of potential savings opportunities for TVA to negotiate. Additionally, we completed four compliance audits of contracts with expenditures totaling $88 million related to providing financial management and consulting services; labor, materials, and equipment; and engineering, design, and construction support. These audits identified potential overbillings of $4.8 million. The Contract Audits section begins on page 23 of this report.

Financial and Operational Audits

In order to ensure that TVA has a reliable system of financial and operational controls, Financial and Operational Audits completed three engagements and reviewed the work of the external auditor related to the audit of TVA's fiscal year (FY) 2010 financial statements. The team applied certain procedures agreed to by management to TVA Winning Performance Incentive Plan results to provide certain assurances to management, the Board, and others prior to incentive plan payouts to employees. The team also reviewed the work of the accounting firm, Ernst and Young LLP, contracted to

audit TVA's 2010 financial statements. Finally, the team reviewed TVA's storage and handling of anhydrous ammonia. The Financial and Operational Audits section begins on page 24 of this report.

IT Audits

To ensure TVA's IT assets are properly secured and appropriate controls are in place, the IT Audits team completed four audits pertaining to: (1) the Federal Information Security Management Act (FISMA); (2) security monitoring; and (3) IT general controls over (a) a third-party hosted application, and (b) applications significant to TVA's FY 2010 financial reporting. The IT Audits section begins on page 26 of this report.

Distributor Audits

To ensure compliance with contract terms between TVA and distributors, the OIG completed three audits of TVA distributors. We looked at classification and metering issues as well as other contract requirements, including the use of electric funds and cash reserves. We also looked at distributor internal controls and identified opportunities for better oversight of distributors by TVA. In addition, Distributor Audits performed a follow-up audit to a 2006 OIG report addressing TVA's role as a rate regulator to determine if the issues identified in that report had been addressed. The Distributor Audits section begins on page 27 of this report.

INSPECTIONS

In order to ensure TVA programs are efficient, effective, and have proper controls in place, Inspections assessed TVA's Dam Safety Program and, as a follow up to previous inspections, reviewed TVA processes and actions pertaining to culture change, stability of ash impoundments, and ash management. The Inspections section begins on page 31 of this report.

INVESTIGATIONS

As part of our mission to ferret out fraud, waste and abuse, one of our investigations led to the first contractor debarment in TVA's nearly 80-year history and payment of a $2 million administrative fee to TVA. Investigations opened 190 cases and closed 161. Our investigators garnered an indictment on false statements, a conviction in a case involving transmission line

STATISTICAL HIGHLIGHTS

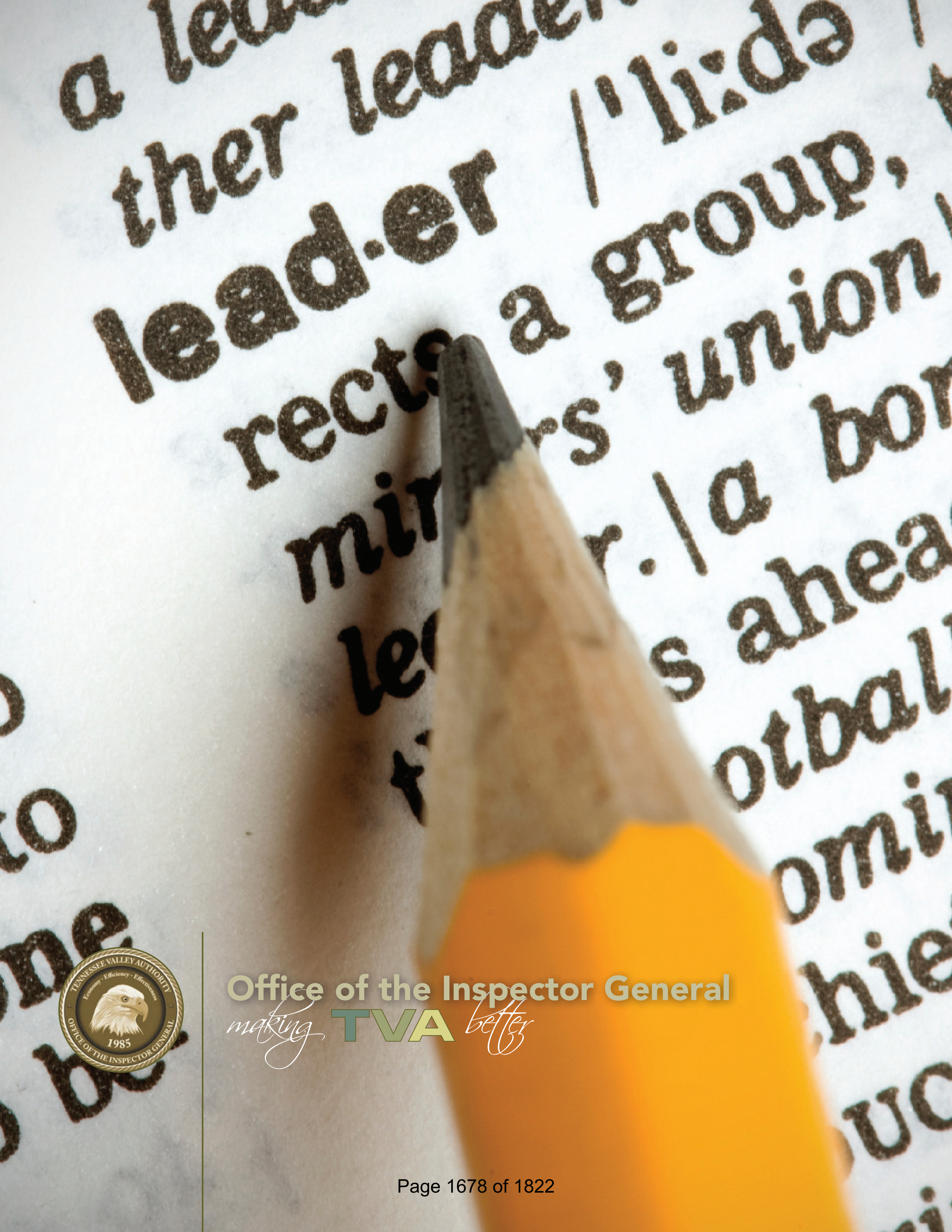
October 1, 2010 – March 31, 2011

Audit Reports Issued	20
Inspections Completed	3
Questioned Costs	$4,846,098
Disallowed Costs	$1,303,202
Funds Recovered	$762,791
Funds to be Put to Better Use	$24,963,000
Funds Realized by TVA	$12,749,961
Investigations Opened	190
Investigations Closed	161
Recoveries/ Savings/Fines/Penalties	$5,111,718
Criminal Actions	2
Administrative Actions (No. of Subjects)	7

Ft. Loudoun Lake

destruction, and the sentencing of four individuals. In total, our investigations resulted in more than $5 million in projected savings, recoveries, fines, and penalties. The investigations section begins on page 35 of this report.

Collectively, during this semiannual period, our Inspections, Audits, and Investigations teams successfully identified almost $35 million in recoveries, fines, penalties, potential savings, questioned costs, and funds that could be put to better use, as shown in the chart to the left.



Office of the Inspector General

making TVA *better*

Office of the Inspector General

The OIG's most important resources are its people. Our team is made up of experienced auditors, investigators, and administrative staff. The OIG is an independent office within TVA and is headquartered opposite TVA corporate offices in TVA's East Tower, overlooking downtown Knoxville. Inspector General Richard Moore believes that in order to effectively provide oversight to TVA, we must be strategic in our placement of OIG employees. As such, the IG has worked to ensure that our office has a presence at or near all major TVA offices throughout the Tennessee Valley.

The OIG has a major satellite office in the Edney Building in Chattanooga, Tennessee, where the Inspections unit and several investigators are located. There are also field offices at the Watts Bar Nuclear Plant in Tennessee; Nashville, Tennessee; Huntsville, Alabama; and Mayfield, Kentucky.

As of March 31, 2011, the OIG had a total staff of 106. The Audits and Inspections units are composed of 58 individuals, the Investigations group includes 30 individuals, and the Administrative team is comprised of 18 people.

The number of personnel located at each office is as follows: Knoxville-82, Watts Bar Nuclear Plant-1, Chattanooga-16, Nashville-2, Huntsville-4, and Mayfield, Kentucky-1.

Administration

The Administration team works closely with the IG, Deputy IG, and Assistant IGs in the conduct of the day-to-day operations of the OIG and to develop policies and procedures designed to drive and enhance productivity in achieving office goals. Responsibilities include operations for personnel administration, budget and financial management, purchasing and contract services, facilities, conferences, communications and IT support.


TVA's Chattanooga Office Complex

Audits and Inspections

The Audits and Inspections group performs a wide variety of engagements designed to promote positive change and provide assurance to TVA stakeholders. Based upon the results of these engagements, the Audits and Inspections group makes recommendations to enhance the effectiveness and efficiency of TVA's programs and operations.

The team uses an impact- and risk-based approach to developing an annual work plan. The group's plan considers TVA's strategic plans, major management challenges, TVA's enterprise risk management process, and other input from TVA management. The planning model also evaluates each potential engagement from the standpoint of materiality (i.e., costs or value of assets), potential impact, sensitivity (including public and/or congressional interest), and the likelihood it will result in recommendations for cost savings or process improvements. The result of the OIG audits and inspections planning process is a focus on those issues of highest impact and risk of fraud, waste or abuse. This focus extends to the field of IT and risk assessment related to a potential malicious or other intrusion of TVA's IT infrastructure.

TVA OIG Organization

Richard W. Moore
Inspector General

Ben R. Wagner
Deputy Inspector General

Investigations Management Team

John E. (Jack) Brennan
Assistant Inspector General, Investigations

Nancy J. Holloway
Special Agent in Charge

Paul B. Houston
Special Agent in Charge

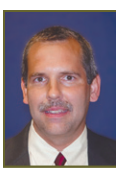
Audits & Inspections Management Team

Robert E. Martin
Assistant Inspector General Audits & Inspections

Phyllis R. Bryan
Director, IT Audits

Lisa H. Hammer
Director, Financial & Operational Audits

Melissa M. Neusel
Director (Acting), Distributor Audits



David P. Wheeler
Director, Contract Audits

Gregory R. Stinson
Director, Inspections

John H. Barrow III
Project Manager Emerging Issues

Louise B. Beck
Audit Quality Manager

Administration Management Team

Jill M. Matthews
Assistant Inspector General Administration

Kay T. Myers
Manager, Human Resources

Stefanie D. Hoglund
Public Affairs Officer

Legal Team

Charles A. Kandt
Legal Counsel

W. David Winstead
Deputy Legal Counsel

The Audits team, based in Knoxville, generates and oversees comprehensive financial and performance audits of TVA programs and operations, providing a landscape view of the organization's overall fiscal and operational health.

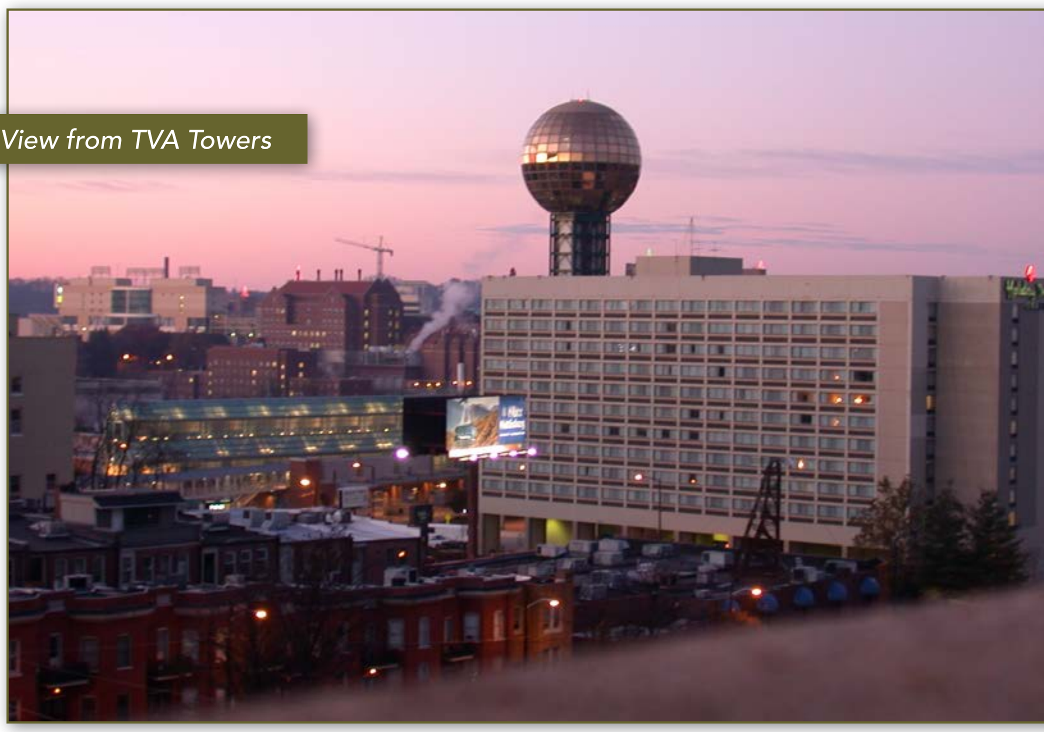
This dynamic team is made up of four departments—Contract Audits, Distributor Audits, Financial/Operational Audits, and Information Technology Audits.

- Contract Audits has lead responsibility for contract compliance and preaward audits. In addition, this group performs reviews of TVA's contracting processes and provides claims assistance as well as litigation support.

- Distributor Audits has lead responsibility for contract compliance reviews of TVA's distributors. This group assesses compliance with the terms of the power contracts between TVA and its distributors and identifies opportunities to improve TVA oversight of its distributors.

- Financial/Operational Audits has lead responsibility for oversight of TVA's financial statement audit and related services performed by TVA's external auditor, reviews of TVA's internal controls related to financial reporting, operational efficiency, and compliance with laws and regulations as well as operational reviews to assess the results and economy and efficiency of TVA programs.

- IT Audits has lead responsibility for audits relating to the security of TVA's IT infrastructure, application controls, and general controls associated with TVA systems. This group also performs operational reviews of the effectiveness of IT-related functions.



Downtown Knoxville | View from TVA Towers

The Inspections team, based in Chattanooga, serves a unique function. This group was created when Inspector General Moore recognized the need for an auditing team that could provide a quick, yet thorough review of TVA functions. We refer to our Inspections group as the "Light Cavalry." This group is able to complete reviews quicker than traditional audits by limiting the scopes of the reviews.

However, the team can and does provide standard reviews which may be broader in scope when needed and seeks to identify when program objectives and operational functions are not effective and efficient. In accordance with the *Quality Standards for Inspections*, the objectives of the Inspections group include providing a source of factual and analytical information, monitoring compliance, measuring performance, assessing the efficiency and effectiveness of operations, and/or conducting inquiries into allegations of fraud, waste, abuse, and mismanagement.

Audit and inspection findings vary depending on the objectives of the project. Issues can be generalized into specific categories depending on the type of engagement performed. The following graphic shows some representative examples of issues commonly reported.

Types of Audit and Inspection Issues

Information Technology Audits

- Unauthorized Access
- Inadequate Controls
- Lack of Data Integrity
- Fraud

Operational Audits

- Operational Inefficiency
- Not Achieving Intended Results
- Inferior Performance
- Legal/Regulatory Noncompliance
- Fraud

Contract Audits

- Inflated Proposals
- Contract Overpayments
- Inferior Performance
- Fraud

Financial Audits

- Internal Control Deficiencies
- Material Misstatements
- Legal Noncompliance
- Fraud

Distributor Audits

- Contract Noncompliance
- Misstatement of Power Sales to TVA
- Fraud

Inspections

- Internal Control Deficiencies
- Operational Inefficiency
- Policy Noncompliance
- Fraud

Major Categories of Investigations

Contract Fraud
Defrauding TVA through its procurement of goods and services. Fraud schemes may include misrepresenting costs, overbilling charges, product substitution, and falsification of work certifications.

Theft of Government Property and Services
Theft of TVA property and "schemes to defraud...designed to deprive individuals, the people, or the government of intangible rights, such as the right to have public officials perform their duties honestly."

Environmental Crime
Violations of environmental criminal law pertaining to the Tennessee River system and its watershed, along with any violations relating to TVA land and facilities. Actively participates with the Environmental Crimes Task Force, Eastern District of Tennessee.

Health Care Fraud
The intentional misrepresentation of health care services, expenses, billings, needs, or coverage that results in unauthorized payments or other benefits.

Illegal Hacking into TVA Computer Systems
Accessing a computer without authorization or exceeding authorized access.

Workers' Compensation Fraud
Includes employee fraud, medical fraud, premium fraud, and employer fraud, most often a false claim of disability to receive benefits.

Employee Misconduct
Generally includes misuse of TVA furnished equipment, travel voucher fraud, and a multitude of miscellaneous matters.

Investigations

The Investigations team proactively searches for activity related to fraud and waste in and abuse of TVA programs and operations. This highly skilled team performs investigative activity in accordance with the *Quality Standards for Investigations*. The investigators maintain liaison with federal and state prosecutors and file a report with the Department of Justice whenever the OIG has reason to believe there has been a violation of federal criminal law. Our investigators partner with other investigative agencies and organizations on special projects and assignments, including interagency law enforcement task forces on terrorism, the environment, and health care. Above are major categories of investigations.

Legal

The OIG Legal Counsel team monitors existing and proposed legislation and regulations that relate to the mandate, operations, and programs of the OIG and/or TVA. In addition, this team provides legal advice as needed for administrative, audits, inspections and/or investigative projects. The OIG Legal Counsel also coordinates government relations for the office.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1985
OFFICE OF THE INSPECTOR GENERAL
Representative Audits
making TVA better

Summary of Representative Audits

During this reporting period, the OIG completed 20 audits which identified approximately $30 million in questioned costs and funds which could be put to better use. The OIG also identified numerous opportunities for TVA to improve program operations. Audits completed this period included: (1) contract preaward and compliance; (2) financial and operational; (3) information technology; and (4) distributors of TVA power.

Contract Audits

Preaward Contract Reviews

To support TVA management in negotiating procurement actions, we completed five preaward audits of cost proposals submitted by companies proposing to provide (1) nondestructive examinations at TVA's nuclear and fossil power generating units, (2) engineering services for work on TVA's Bellefonte Nuclear Plant Unit 1, and (3) geotechnical services. Our audits identified almost $25 million of potential savings opportunities for TVA to negotiate. The savings opportunities were primarily related to overstated wage rates and indirect cost recovery rates.

Contract Compliance Reviews

During this semiannual period, we completed four compliance audits of contracts with expenditures totaling $88 million and identified potential overbillings of $4.8 million. Highlights of our completed compliance audits follow.

- We audited $51.2 million in costs that a contractor billed to TVA under two contracts for financial management and consulting services. Our audit objective was to determine if the costs, which were billed from July 2003 through December 2008, were in compliance with the provisions of the contracts. In summary, we found $4.8 million of costs billed by the contractor were unsupported or not in accordance with the terms of the contracts as follows.

  - $3,328,704 was overbilled because the contractor did not limit its overtime billings as represented in their proposals and in the final terms of one contract. (The overbilling included about $890,000 that occurred from the end of our audit period through March 31, 2010.)

  - $514,669 in labor costs were overbilled due to unapproved job categories or incorrect billing rates, timesheet discrepancies, and unallowable administrative labor.

Bellefonte Nuclear Plant

  - An estimated $51,233 was billed for unallowable or unsupported travel expenses and travel agency fees.

  - $1,020,454 in overbillings occurred because work was performed prior to the issuance of a contract work authorization (CWA) or not authorized under the terms of the CWA or costs exceeded the CWA funding limits.

The overbillings itemized above included $108,877 that was counted in more than one finding. Accordingly, the net overbilling after removing this duplication was $4,806,183. TVA management is reviewing

our recommendations to determine what actions to take.

- We audited $6.9 million in payments TVA made to a contractor under two contracts from January 5, 2004, through April 19, 2010, for providing labor, material, and equipment to re-clear or provide maintenance of existing transmission line right-of-way. In summary, we found the contractor had overbilled TVA about $1,400 due to miscellaneous billing errors. However, TVA's invoice approvers had found and adjusted most of the errors prior to paying the contractor.

- We audited $24.9 million in payments made by TVA from 2007 through 2009 to a contractor for providing engineering, design, and construction support. In summary, we found the contractor overbilled TVA an estimated $39,915 including (1) $26,182 in overbilled labor and fee costs and (2) $13,733 in overbilled direct costs. We recommended TVA management take action to recover the overbilled costs. The contractor agreed with our findings and issued a credit to TVA for the overbillings.

- We audited $5 million in provisional billings for indirect costs by a contractor that provided security services at TVA's nuclear plants during 2009. We found the contractor owed TVA $746,482 due to its actual costs being less than the amounts provisionally billed during calendar year 2009. However, prior to our audit the contractor reimbursed TVA $804,586 based on its preliminary estimate of the amount due TVA. As a result, the amount refunded to TVA was overstated by $28,104.

Transmission Lines

Financial and Operational Audits

During this semiannual period, we completed four engagements, including the audit of TVA's storage and handling of ammonia, performance of agreed-upon procedures for 2010 Winning Performance payouts; and monitoring of TVA's external auditor's FY 2010 audit of TVA's financial statements. Highlights of our completed reviews follow.

TVA's Storage of Ammonia

We reviewed TVA's storage and handling of anhydrous ammonia to determine whether (1) TVA's policies and procedures complied with relevant ammonia-related Occupational Safety and Health Administration (OSHA) and other federal regulations, and (2) TVA fossil plants were in compliance with TVA's policies and procedures covering ammonia storage and management. In addition, we assessed the general physical security surrounding TVA's ammonia storage tanks and related supports.

In summary, we determined:

- TVA has two procedures intended to implement certain OSHA requirements. However, (1) TVA does not have a formal policy addressing American National Standards Institute (ANSI) and OSHA requirements regarding storage and handling of anhydrous ammonia; (2) TVA's Process Safety Management procedure does not address

all of the OSHA requirements; and (3) certain sites did not (a) complete all of the process hazard analysis requirements included in TVA's Process Safety Management procedure, (b) certify their operating procedures on an annual basis, (c) follow ammonia training requirements for their employees or have a mechanism for ensuring that the required training of their employees who handle ammonia or perform maintenance on ammonia systems was completed timely, and (d) satisfy the nameplate and/or marking requirements for their ammonia storage tanks as required by ANSI.

- No method exists to inform visitors or nonplant TVA personnel that ammonia training may be required prior to entering the plants, other than the requirements provided for in one of TVA's procedures or reliance upon that visitor's or nonplant employee's site contact.

- Differences exist in the way ammonia storage tanks are protected among the seven plants visited.

We made recommendations to TVA's Designated Agency Safety and Health Official. TVA management generally agreed with our recommendations and has taken or is taking actions to address these recommendations.

Agreed-Upon Procedures Applied to 2010 Winning Performance Payouts

TVA's Winning Performance (WP) Incentive Plan is a performance management program designed to promote teamwork, focus on continued high performance, and motivate and reward employees for achieving strategic objectives and critical success factors. The WP program is based on the principle that operational improvements, reduced costs, and improved revenues can be achieved by applying management focus and offering monetary incentives.

Paradise Fossil Plant

We applied four agreed-upon procedures requested solely to assist management in determining the validity of the WP payout awards for the year ended September 30, 2010.

In summary, we found:

- The FY 2010 WP goals were properly approved. Between April 16, 2010, and November 2, 2010, the Chief Executive Officer (CEO) approved nine change forms affecting 16 measures and/or payout percentages. The 16 affected measures and/or payout percentages resulted in nine increases and three decreases to the payout.

- Actual year-to-date inputs for all the metrics agreed with the respective supporting documentation.

- The actual year-to-date inputs for two incentivized metrics agreed with the respective supporting documentation.

- The payout percentages provided were recalculated and compared without

exception. Subsequent changes to actual data and goals were received through November 5, 2010. We recalculated the payout percentages based on the revised data without exception. A subsequent change to the actual year-to-date metric measure was received through November 9, 2010, but it did not impact payout percentages. In addition, one organization's payout percentage was reduced by 4.89 percent based on an approved change form.

FY 2010 Financial Statement Audit

TVA contracted with the independent public accounting firm of Ernst & Young LLP to audit TVA's balance sheet as of September 30, 2010, and the related statements of income, changes in proprietary capital, and cash flows for the year then ended. This also included the audit of TVA's internal controls over financial reporting as of fiscal year end. The firm also reviewed TVA's FY 2010 interim financial information filed on Form 10-Q with the Securities and Exchange Commission (SEC). The contract required the work be performed in accordance with generally accepted government auditing standards. Our monitoring of this work disclosed no instances where the firm did not comply, in all material respects, with generally accepted government auditing standards.

IT Audits

During this semiannual period, we completed four audits in the IT environment pertaining to: (1) FISMA; (2) security monitoring; and (3) IT general controls over (a) a third-party hosted application, and (b) applications significant to TVA FY 2010 financial reporting.

FISMA Review Identified Needed Improvements

In accordance with FISMA and guidance from the Office of Management and Budget, TVA and the TVA OIG are required to report on agency-wide information technology security and privacy practices annually. In our 2010 review of TVA's information security program, we found TVA had made significant improvements in two FISMA control areas in the past year. However, overall progress in implementing IT controls required by FISMA had slowed while TVA continued work on previously recommended actions and redesigned some processes. Additional efforts were needed to improve compliance with existing controls and address concerns identified in the following control areas: (1) certification and accreditation process, (2) security configuration management, (3) incident response and reporting, (4) security training, (5) remote access, and (6) contingency planning.

TVA Improved Cyber Security Incident Response

In 2009, the OIG completed an audit on the state of IT Cyber Security monitoring within TVA which identified areas for improvement. At the request of TVA's CEO and Audit, Risk, and Regulation Committee, we re-evaluated the effectiveness

of controls and processes in place to (1) monitor for, (2) identify, and (3) respond to cyber security events. We assessed progress toward completing actions in response to findings and recommendations in our previous audit. While we found TVA had improved its ability to detect and respond to cyber security attacks, we identified several areas where the program could be further improved.

Weak IT General Controls at an Application Service Provider

We audited the IT general controls for an application hosted by a third party vendor. TVA uses the application to manage contractor requests and approval, selection, time reporting/billing, and reporting for noncraft staff augmentation contractors. We determined control weaknesses existed in the areas of (1) account management, (2) system configuration management, and (3) computer operations. We also determined TVA's contract language could be improved by developing a standard clause that addressed the protection of TVA proprietary information stored on vendors' systems.

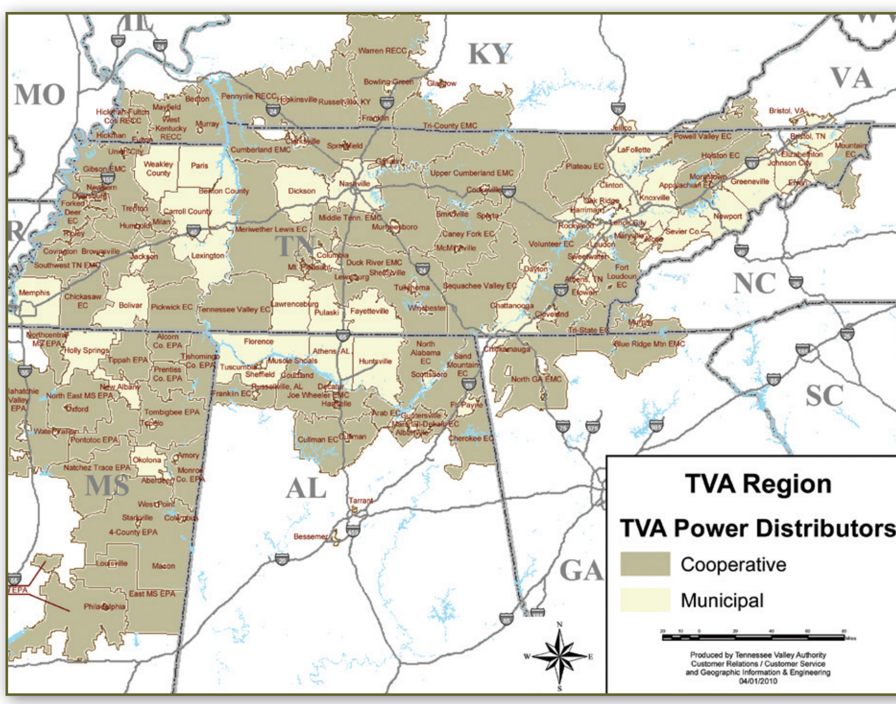
IT General Controls for Financial Reporting were Generally Effective

When Congress passed the Consolidated Appropriations Act of 2005 which established the new nine member board for TVA, it also included requirements that TVA comply with SEC reporting requirements including certain provisions of the Sarbanes-Oxley Act. We tested 30 control activities within five IT general control domains and seven applications designated by TVA as requiring supplemental testing for FY 2010 financial reporting. The purpose of testing was to provide control owners with the status of operating effectiveness of primary control activities at the end of FY 2010. We determined 19 control activities were operating as designed, two were not operating effectively, four could be improved, and five could not be tested due to the nonoccurrence of an activity that would trigger the control operation.

Distributor Audits

TVA has 155 distributors –municipalities and cooperatives – that resell TVA power to consumers across the Tennessee Valley. Power sales to these distributors comprise about 85 percent of TVA's operating revenue. Distributor Audits evaluates these distributors to assess compliance with key power contract provisions, including: accurate reporting of electric sales by customer class to facilitate proper revenue recognition and billing by TVA; nondiscrimination in providing power to members of the same rate class; and the use of power revenues. Additionally, Distributor Audits makes recommendations to help (1) distributors improve their internal controls, and (2) TVA management improve its oversight of the distributors.

During this semiannual period, the OIG completed three distributor audits. In addition, we performed a follow-up audit to a 2006 OIG report addressing TVA's role as an electric rate regulator to determine if the issues identified in that report had been addressed. The following describes the issues noted in one or more of the three completed distributor audits.



Classification and Metering | We noted instances where customers were not classified properly and similar customers were not classified the same. The impact of these issues, where we had adequate information to estimate, was not significant; however, there were some instances where we did not have enough information to estimate the impact. Generally, the distributors agreed with our findings and have already corrected or are taking action to correct these issues.

Other Contract Requirements | We found distributors were not complying with certain other contract requirements. Specifically, we noted: (1) contracts were not in place for all customers whose demand exceeded 1 megawatt; and (2) cost allocations for joint use of property and services approved by TVA were not being applied; instead, other allocation methods not approved by TVA were used, and/or allocations were applied improperly; (3) accounts were not classified in accordance with Federal Energy Regulatory Commission requirements; (4) required applications for customers receiving the Small Manufacturing Credit were not obtained; (5) the Enhanced Growth Credit (EGC) was not calculated correctly for all customers; (6) required EGC documentation was not maintained; and (7) a spreadsheet used by a distributor to calculate electric sales reported to TVA contained an error, causing the distributor to overpay TVA for demand by approximately $104,000. Generally, TVA and the distributors agreed and have already corrected or are taking action to correct these issues.

Use of Electric Revenues | We found one of the three distributors reviewed had more than enough cash on hand to fund planned/actual capital expenditures and provide cash reserves exceeding the minimum TVA guidelines of a cash ratio of 5 to 8 percent, and one distributor used electric department funds for nonelectric businesses without obtaining appropriate written agreements with TVA.

Cash Reserves | While TVA has established guidelines to determine if a distributor has adequate cash reserves (a cash ratio of 5 to 8 percent), TVA has not established guidelines to determine if a distributor's cash reserves are excessive. One of the three distributors reviewed had a cash ratio exceeding the minimum guidelines of 5 to 8 percent. TVA has agreed to define criteria for determining when a distributor's cash reserves are excessive.

Use of Funds for Nonelectric Purposes | One of the three distributors reviewed used electric department funds for nonelectric businesses without obtaining appropriate written agreements with TVA. The distributor (1) used electric system funds to pay for expenses of the broadband department without approval from TVA and (2) did not have loan documents in place between the electric department and the broadband department that specified interest rates, payment amount, and recourse protections. Without an executed loan document, the electric department has no legal recourse to recover amounts expended to fund the broadband department. TVA and the distributor agreed to take corrective action.

Distributor Internal Control Issues | At one of the distributors audited, we found improvements could be made with respect to remediating a billing agency programming error that resulted in customers not receiving correct refunds. The distributor agreed and is taking action to correct the issue.

Opportunities for TVA Oversight Improvements | We found opportunities to enhance TVA's oversight at each of the three distributors that had also been reported in previous OIG distributor audit reports. In response, TVA agreed to take corrective action on these issues.

Follow-up Review of TVA's Role as a Rate Regulator

In a 2006 OIG report, we recommended TVA execute contract modifications with distributors who wish to pursue nonelectric business ventures, and TVA management agreed to do so. However, during our follow-up audit, TVA management informed us that an alternative approach to protect the interests of TVA and other parties had been implemented. Instead of formal contract modifications, TVA will require written agreements with terms to protect all parties

Transmission Lines

when approving a distributor's investment of "reserves for renewals, replacements, contingencies, and working capital" in nonelectric business ventures.

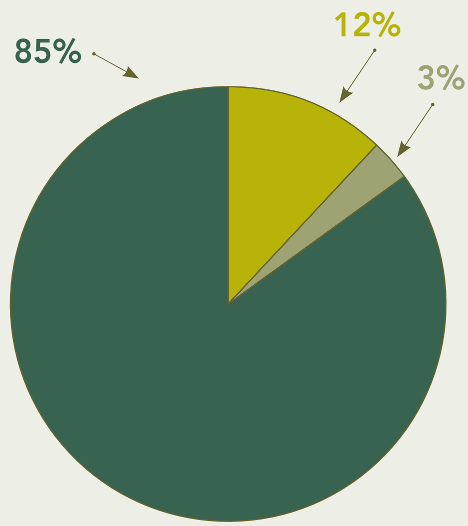
TVA designated one distributor's request evaluation and subsequent agreements as the "model" for handling future requests. While the new approach and "model" may prove effective for controlling risks, we noted three areas where protection for the distributors, ratepayers, and TVA could be strengthened. TVA has corrected one of the issues. Specifically, we found TVA had not:

- Established guidelines to indicate when a distributor's cash reserves are excessive and should be returned to the ratepayers through rate reductions, as required by the power contract. TVA has made some progress in formalizing procedures and metrics for review of a distributor's financial position; however, the procedures and metrics have not been approved and implemented.
- Reviewed distributors previously approved to use electric system revenues for nonelectric purposes, or reviewed those distributors that were using funds without approval, to determine if appropriate protections (e.g., formal written agreements) were in place.

TVA agreed to take action on these issues. TVA corrected a third issue by documenting (1) guidelines for reviewing business plans when a distributor proposes to invest in nonelectric ventures or use electric system revenues for nonelectric purposes and (2) the terms to be included in the resulting formal written agreements.

TVA CUSTOMERS

FY 2010 Revenue by Customer



- **155 Distributors - municipalities/ cooperatives | 85%**
- **Industries (directly served) | 12%**
- **Federal Agencies (directly served) and Other Revenue Sources | 3%**

Representative Inspections

making TVA better

Summary of Representative Inspections

During this reporting period, Inspections completed three reviews including the assessment of (1) TVA's Dam Safety Program; and (2) processes in place to address deficiencies in ash management governance, cultural issues, the stability of ash impoundments, and deficiencies in the coal ash management program.

Review of TVA's Dam Safety Program Identified Areas for Improvement

This review was the result of broad interest by the media, TVA stakeholders, and the public at large surrounding the safety and condition of TVA dams after the ash spill at the Kingston Fossil Plant. TVA's Dam Safety organization (Dam Safety) is responsible for ensuring that TVA's Dam Safety Program, formalized in 1982, meets federal guidelines. TVA's Dam Safety Program consists of modifications to ensure the structural integrity and safe operation of TVA's 49 dams and related structures, instrumentation to monitor dam performance, periodic inspections, maintenance and repairs, as well as emergency preparedness. In addition, Dam Safety's scope of responsibility includes saddledams, dikes, and impoundments in the TVA system.

The objectives of our review were to determine if TVA's Dam Safety Program identified and adequately addressed significant risks; was in compliance with TVA policies and procedures, as well as applicable laws and regulations; and encompassed all aspects of a comprehensive dam safety program. Our review found TVA was taking steps to identify and mitigate its risks; was adhering to the Federal Guidelines for Dam Safety, with a few exceptions; and had a comprehensive dam safety program. Specifically:

- TVA was moving from a reactive to a proactive posture by anticipating and mitigating risks. According to TVA's Hydro Board of Consultants, an independent team of three internationally recognized experts in dam engineering retained by Dam Safety, it would be very difficult for something to happen that would not be detected in time to mitigate disaster with the monitoring TVA has in place. In addition, TVA was implementing new analysis to assist with the identification and mitigation of risk, based on recommendations by TVA's independent consultants. However, based on interviews with TVA plant personnel, clearer lines of responsibility; decreased lag time from inspection to report issuance; rotation of inspectors; and Dam Safety personnel presence during project work would enhance the identification and mitigation of dam safety risks.

- TVA's policy was to follow the Federal Guidelines for Dam Safety, although not required under federal law. TVA was adhering to the federal guidelines, with the exception of certain aspects of the operations and maintenance (O&M) manuals, Training and Awareness Program, and emergency action plans (EAPs). Specifically, O&M manuals were not updated on a regular basis and periodic evaluation was not performed of site personnel conducting monthly inspections. Additionally, the EAPs lacked a process for terminating an emergency, a designated EAP Coordinator, and information related to unmanned dams. These deficiencies could hinder risk identification and mitigation activities.

Nickajack Lake

- We contracted with Marshall Miller to conduct a peer review of TVA's Dam Safety Program. Based on Marshall Miller's review, it appeared that while TVA had a comprehensive dam safety program in place, the program could be strengthened in the areas of inspection, instrumentation, Dam Safety O&M programs, and emergency action planning.

Additionally, there were several issues identified in this review that were previously identified in our inspection report titled, ***Review of Kingston Fossil Plant Ash Spill Root Cause Study and Observations about Ash Management*** (Kingston Report). The Kingston Report noted areas where responsibility and accountability were unclear. Maintenance was also identified as a "big problem" and we noted staffing and funding should be increased, and the O&M manuals needed to be updated. Since these issues negatively impacted TVA management of ash impoundments, we recommended the potential impact and risk of parallel issues identified in this review be thoroughly examined by TVA as part of its effort to change the company's culture. TVA management agreed with our findings and recommendations and has taken or plans to take corrective actions.

Stability Assessment Process Review Determined TVA Responded Appropriately to the 2008 Kingston Ash Spill

The OIG identified weaknesses in TVA culture and the coal ash management program in previous inspections. This review was initiated to assess and report on the appropriateness of TVA processes, and completed and planned actions pertaining to culture change, stability assessments of TVA ash impoundments, and ash management.

The objectives of this review were to determine what processes TVA had followed since the Kingston Fossil Plant ash spill to address: (1) deficiencies in ash management governance, (2) cultural issues identified, (3) stability of the other coal ash impoundments, and (4) deficiencies in the coal ash management program. The scope of this review included information available to the OIG regarding coal ash management and risk.

We found that since the Kingston Fossil Plant ash spill, TVA had taken appropriate actions to: (1) improve

Kingston Fossil Plant

ash management governance, (2) drive culture change, (3) evaluate the stability and corresponding safety factors pertaining to ash impoundments, (4) remediate risks, and (5) identify and address ash management deficiencies. Specifically, TVA had:

- Decided to include coal ash impoundments under the Dam Safety Program to increase governance and use the expertise of TVA's independent hydro review board in assessing the safety and stability of coal ash impoundments.

- Taken action to drive organizational culture change, including hiring an independent cadre of professionals to assess TVA culture, instituting an organizational effectiveness initiative, and reorganizing to improve accountability.

- Hired a consultant, Stantec, Inc., to evaluate the stability of facility ash impoundments and established an appropriate evaluation and remediation process.

- Taken immediate actions to improve stability and remediate risks pertaining to many TVA coal ash impoundments.

- Compiled a gap analysis of recommendations to TVA from relevant review sources to ensure ash management problems were addressed. The development and implementation of the quality assurance/quality control processes and development of ash management policies and procedures are examples of key actions taken.

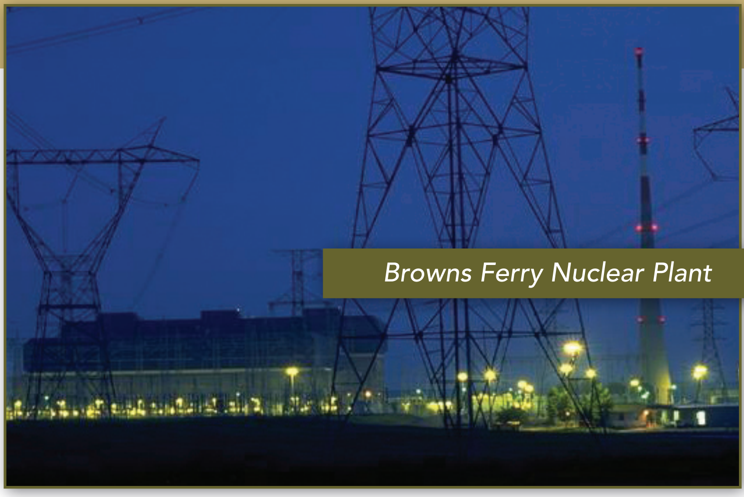
While TVA has made significant progress to-date, it is important to note this is a long-term project that TVA must continue as a priority.

Representative Investigations

making **TVA** *better*

Summary of Representative Investigations

During this reporting period, one of TVA OIG's investigations led to TVA's first contractor debarment and a $2 million administrative fee due to TVA. Investigations opened 190 cases and closed 161. Our investigators garnered an indictment on false statements, a conviction in a case involving transmission line destruction, and the sentencing of four individuals. In total, our investigations resulted in more than $5 million in projected savings, recoveries, fines, and penalties.



Browns Ferry Nuclear Plant

Contractor Misconduct Leads to First TVA Debarment and the Collection of $2 Million Administrative Fee

The OIG previously reported that a TVA technical contract manager received money from a TVA contractor. Criminal actions were taken against the former TVA technical contract manager in that investigation. In addition, a report of administrative inquiry was issued to TVA management regarding the actions of the contractor, Holtec International, Inc. In response to this report, TVA established and filled the position of a TVA suspension and debarment officer to review the matter, which led to the first debarment action at TVA. Holtec International, Inc., received a sixty-day debarment (October 12 through December 12, 2010); and, by agreement with TVA, will pay a $2 million administrative fee to TVA; appoint a corporate governance officer and an independent monitor (at the contractor's expense); implement a code of conduct, to include training for all employees, executives, directors, and officers; add three noncompany members to its board of directors and sign an administrative agreement ensuring compliance to the above terms.

TVA Program Manager Receives a 30-Day Suspension Following an OIG Investigation

TVA OIG addressed an allegation that a custodial program manager was using TVA employees, equipment and supplies to run a private cleaning company. The manager's company has a contract to provide janitorial services to city buildings in the TVA region of responsibility. The investigation determined the employee did utilize a TVA vehicle during the normal TVA work schedule to do non-TVA work, and the individual was untruthful about this use during an interview. The OIG issued a report, and TVA management responded by suspending the individual for 30 days without pay, issuing the employee a written warning, and requiring the employee to complete a request for approval of outside employment and a financial disclosure form. Additionally, all regional custodial/facilities maintenance employees were required to complete TVA's 2010 ethics training, and the custodial supply rooms were made more secure to prevent misuse. Also, TVA Facilities O&M group agreed to perform a cost-benefit analysis regarding installation of a security system to track entrances and exits to all custodial supply rooms accessible by noncustodial employees, analyze monthly use of custodial supplies to identify unsupportable use, and remind employees of TVA policy regarding misuse of government property.

Watts Bar Nuclear Plant

Chemistry Process at Watts Bar Nuclear Investigated

The OIG investigated a complaint that chemistry records were destroyed during an outage at Watts Bar Nuclear Plant. The complaint alleged that a TVA manager was told ahead of time that polishers, (which purify water) were in danger of failing, the result of which would be unacceptably elevated chemical concentrations immediately before re-start. The manager decided not to replace the polishers and they failed. In addition, steam generator samples were out of acceptable pressurized water reactor secondary water chemistry guidelines as set forth by the Electric Power Research Institute, and were destroyed by instruction of the same manager and removed from the computer database. The investigation concluded the facts as alleged were largely accurate, but that the actions of the manager were not technically in violation of written policy and procedure. A report to management was submitted, with which management generally agreed. As a result of our investigation, TVA's Watts Bar Chemistry manual was revised regarding the deletion and retention of data.

Missing Tools Located, TVA Credited

In a prior semiannual period, we received information from a TVA program manager that tools were missing from a spring 2010 outage at the Cumberland Fossil Plant. The missing tools were possibly utilized by an electrical contractor who had been assigned $26,000 in tools by TVA tool management personnel. At the completion of the outage, the contractor failed to account for approximately $23,000 in tools. Two separate searches of the contractor's shop uncovered $5,939 in tools that clearly belonged to TVA. Following the searches, the contractor had a total of $18,666 in tools they failed to return to TVA. This amount was credited to TVA. Additional walk-downs at the Cumberland plant revealed $88,219 in unaccounted for tools and equipment.

Two fossil plants had procedures already in place to inventory contractor tools and equipment at the beginning and the completion of outages. We recommended Fossil management adopt a similar procedure for all fossil plants and have plant security conduct periodic vehicle searches of contractors exiting the plants. Fossil management agreed to develop and implement a procedure for all TVA fossil plants, which was implemented this reporting period, and TVA Police is presently reviewing additional security needs at the plants.

Two Convicted for Destruction of TVA Property

On September 8, 2009, at approximately 9:50 a.m., the Marshall-Murray 161 kV transmission line failed causing a power outage in Marshall and Calloway Counties, and the City of Murray, Kentucky. A TVA electrician responding to the power outage noticed that insulators had been shot at structure No. 331 on the property at 1265 Pugh School Road, Benton, Kentucky. A joint investigation was conducted with the TVA Police. A $1,000 reward was posted for information leading to the arrest and conviction of the person or persons responsible for the damage to the transmission line. Our investigation resulted in the identification and conviction of two individuals: one convicted and sentenced last year; one during this reporting period. Both pled guilty in state court to one count of Criminal Mischief 2nd Degree, were sentenced to one year in jail, two years' probation, as well as

fined $160 in court costs and ordered to pay restitution to TVA in the amount of $4,300.

Allegation of Unethical Relationship Substantiated

TVA Office of the General Counsel reported to the OIG an allegation that a subcontracting company working under a TVA custodial provider contract was owned and operated by the wife of a facilities custodial manager. The subcontractor worked in the area supervised by the TVA manager. TVA's contract manager was unaware of the relationship. Our investigation substantiated the allegation, and a report was issued to TVA management, who responded appropriately to ensure the conflict was addressed and that measures were taken to prevent future ethical conflicts.

OIG Followed Up on Concerns Regarding Dam Safety

In conjunction with OIG Inspections, Investigations performed a risk-based special project concerning TVA's Dam Safety Program. The project closed this semiannual period. Investigations had received information that Wheeler Dam Unit 1 had structural issues, and that Wilson Dam had waterfalls on the downstream side of the dam possibly originating from seepage from the upside of the dam. Investigations performed reviews of the Wheeler, Wilson, Bear Creek (nonpower), Nickajack, and Douglas sites. Investigations issued a report to TVA management concerning Wheeler Dam. OIG Inspections reported the results of the reviews at the other sites. Management responded by obtaining an independent third party assessment of Wheeler Dam Unit 1, installing additional sensors to measure vibration, and issuing new written procedures concerning start, stop and operation of the unit.

TVA Subcontract Manager Sentenced

A TVA subcontract manager and an accomplice were sentenced after pleading guilty to felony mail fraud and related counts. The involved individuals falsified invoices for labor and materials related to preheating welds at Browns Ferry Nuclear Plant. The subcontract manager was sentenced to 14 months probation (eight of those months are in home confinement) and his accomplice was sentenced to 12 months probation (four months in home confinement). The two were jointly and severally ordered to pay $31,855 in restitution.

Former TVA Employee Sentenced on Stealing Four Credit Cards

A former TVA employee at Allen Fossil Plant was sentenced in Tennessee state court after pleading guilty to theft of four TVA gas purchase credit cards. The individual was also required to pay restitution to TVA of $16,262.

Wheeler Dam

Legislation and Regulations

making TVA better

Legislation and Regulations

In fulfilling its responsibilities under the IG Act of 1978, as amended, the OIG follows and reviews existing and proposed legislation and regulations that relate to the mandate, operations and programs of TVA. Although TVA's Office of the General Counsel reviews proposed or enacted legislation that could affect TVA activities, the OIG independently follows and reviews proposed legislation that affects the OIG and/or relates to economy and efficiency or waste, fraud, and abuse of TVA programs or operations.

The TVA OIG has been tracking the following major pieces of legislation during the past six months:

S. 413 – The Cybersecurity and Internet Freedom Act

Senator Joseph Lieberman (D-CT) introduced this legislation which would amend the Homeland Security Act of 2002 "to protect and enhance the Nation's cybersecurity infrastructure." S. 413 would establish an Office of Cyberspace Policy in the Executive Office of the President that would develop national strategies to increase cyberspace security and resiliency. It would also establish a National Center for Cybersecurity and Communication (NCCC) within the Department of Homeland Security (DHS) to implement the national strategies of the Office of Cyberspace Policy. IGs would be required to assess the adequacy and effectiveness of their agency's information security programs every two years. IGs would also be required upon request to give law enforcement information related to the security of the federal information infrastructure to the Director of United States Computer Emergency Readiness Team. Agencies that fail to comply with corrective measures in accordance with DHS recommendations must submit a report to their agency IG explaining why; and agencies must ensure that information relating to the adequacy and effectiveness of information security practices is available to IGs on an automated and continuous basis.

S. 493 – The SBIR/STTR Reauthorization Act

The bill was introduced on March 4, by Senator Mary Landriue (D-LA) and passed the Senate Committee on Small Business and Entrepreneurship on March 9. Among other things, S. 493 directs the Small Business Administration to revise the Small Business Innovation Research (SBIR) and Small Business Technology Transfer (STTR) policy directives to require IGs at granting agencies to take steps to prevent fraud, waste, and abuse. Such measures would include coordinating information sharing between agencies; improving education, training, and outreach; and establishing an SBIR/STTR fraud hotline. Members of the CIGIE Legislation Committee are currently working with Allison Lerner, National Science Foundation IG and Chair of the CIGIE Misconduct in Research Working Group, to address concerns regarding IG independence and to propose requiring lifecycle certifications by every small business entity that applies for or receives an award under one of the programs.

Office of Government Ethics (OGE) Draft to Amend Ethics in Government Act

OGE recently circulated for comment a draft of its new legislative proposal to amend the Ethics in Government Act (EIGA). Among other things, it would amend Section 403 of EIGA to provide the OGE Director with the authority to request an IG to investigate an ethics matter. The IG may decline the request, but the IG must provide a written reason for the declination within 30 days. The draft would also require agencies to notify OGE of any relevant IG investigations

as soon as the IG determines there are grounds to believe a conflict of interest violation has occurred.

Four Bills Would Establish New IGs

H.R. 727 and S. 348 would each create a Judicial Branch IG, who would be appointed to a four year term.

H.R. 808 (The Department of Peace Act) would establish a Cabinet level department in the Executive Branch with a presidentially appointed IG for the department. Notably, there is not an explicit requirement that the IG be appointed with the advice and consent of the Senate.

S. 428 introduced by Senator Claire McCaskill (D-MO), establishes an IG for the Senate. The IG would be appointed jointly by the Senate majority and minority leaders and would be under their general supervision. The IG would serve a term of five years and would be limited to two reappointments.

Ongoing Matters

There has been no further action on S. 241 (The Non-Federal Employee Whistleblower Protection Act); S. 300 (The Government Charge Card Abuse Prevention Act); or H.R. 209 (The Reducing Information Controls Designations Act). We continue to be interested in these bills and will closely monitor them.

Cades Cove | Great Smoky Mountains National Park

Appendices

making TVA better

Appendix 1

INDEX OF REPORTING REQUIREMENTS UNDER THE INSPECTOR GENERAL ACT

REPORTING	REQUIREMENT	PAGE
Section 4(a)(2)	Review of Legislation and Regulations	39-40
Section 5(a)(1)	Significant Problems, Abuses, and Deficiencies	23-37
Section 5(a)(2)	Recommendations With Respect to Significant Problems, Abuses, and Deficiencies	23-37
Section 5(a)(3)	Recommendations Described in Previous Semiannual Reports in Which Corrective Action Has Not Been Completed	Appendix 4
Section 5(a)(4)	Matters Referred to Prosecutive Authorities and the Prosecutions and Convictions That Have Resulted	Appendix 5
Section 5(a)(5) and 6(b)(2)	Summary of Instances Where Information Was Refused	None
Section 5(a)(6)	Listing of Audit and Inspection Reports	Appendix 2
Section 5(a)(7)	Summary of Particularly Significant Reports	23-37
Section 5(a)(8)	Status of Management Decisions for Audit and Inspection Reports Containing Questioned Costs	Appendix 3
Section 5(a)(9)	Status of Management Decisions for Audit and Inspection Reports Containing Recommendations That Funds Be Put to Better Use	Appendix 3
Section 5(a)(10)	Summary of Audit and Inspection Reports Issued Prior to the Beginning of the Reporting Period for Which No Management Decision Has Been Made	None
Section 5(a)(11)	Significant Revised Management Decisions	None
Section 5(a)(12)	Significant Management Decisions With Which the Inspector General Disagreed	None
Section 5(a)(13)	Information Under Federal Financial Management Improvement Act of 1996	None
Section 5(a)(14)	Appendix of results of any peer review conducted by another Office of Inspector General during the reporting period and, if none, a statement of the date of the last peer review.	Appendix 8
Section 5(a)(15)	List of outstanding recommendations from any peer review conducted by another Office of Inspector General, including a statement describing the status of the implementation and why implementation is not complete.	None
Section 5(a)(16)	List of peer reviews conducted of another Office of the Inspector General during the reporting period, including a list of any outstanding recommendations made from any previous peer review that remain outstanding or have not been implemented.	Appendix 8

Appendix 2

OIG AUDIT REPORTS ISSUED DURING THE SIX-MONTH PERIOD ENDED MARCH 31, 2011

Report Number and Date	Title	Questioned Costs	Unsupported Costs	Funds Put To Better Use
CONTRACT AUDITS				
2010-13249 10/19/2010	DF&K Right-of-Way Clearing	$0	$0	$0
2008-11553 10/27/2010	Deloitte Consulting, LLP	$4,806,183	$0	$0
2010-13058 10/27/2010	WorleyParsons	$39,915	$523	$0
2010-13463 12/01/2010	Pinkerton Government Services	$0	$0	$0
2010-13485 01/21/2011	Preaward Review – Proposal to Provide Nondestructive Examinations at TVA Nuclear and Fossil Generation Units	$0	$0	$1,159,000
2010-13503 01/26/2011	Preaward Review – Proposal for Bellefonte Nuclear Plant Unit 1 Master Completion Contract	$0	$0	$4,900,000
2010-13550-01 02/16/2011	Preaward Review – Proposal to Provide Engineering Services for Bellefonte Nuclear Plant Unit 1	$0	$0	$7,300,000
2010-13550 03/03/2011	Preaward Review – Proposal to Provide Engineering Services for Bellefonte Nuclear Plant Unit 1	$0	$0	$11,543,000
2010-13643 03/08/2011	Preaward Review – Proposal to Provide Geotechnical Services	$0	$0	$61,000
DISTRIBUTOR AUDITS				
2009-12699 12/09/2010	Follow-up Review of TVA's Role as a Rate Regulator – Use of Electric Revenues for Nonelectric Purposes	$0	$0	$0
2010-13021 12/09/2010	Pulaski Electric System	$0	$0	$0
2010-13025 01/04/2011	North Georgia Electric Membership Corporation	$0	$0	$0
2010-13024 02/08/2011	Newport Utilities	$0	$0	$0
FINANCIAL AND OPERATIONAL AUDITS				
2010-13251 10/04/2010	TVA Storage and Management of Ammonia	$0	$0	$0
2010-13596 11/10/2010	Agreed-upon Procedures Applied to TVA Fiscal Year 2010 Performance Measures	$0	$0	$0
2010-13143 03/21/2011	Review of the Rework on Watts Bar Unit 2	$0	$0	$0
INFORMATION TECHNOLOGY AUDITS				
2010-13033 10/12/2010	Effectiveness of Cyber Security Monitoring Follow-up Review	$0	$0	$0
2010-13507 10/22/2010	Sarbanes Oxley Testing – IT General Controls and Application Control Narratives	$0	$0	$0
2010-13446 12/02/2010	Federal Information Security Management Act (FISMA) Evaluation	$0	$0	$0
2010-13077 02/17/2011	Contractor Workforce Management Application Security Assessment	$0	$0	$0
TOTAL AUDITS (20)		**$4,846,098**	**$523**	**$24,963,000**

OIG INSPECTION REPORTS ISSUED DURING THE SIX-MONTH PERIOD ENDED MARCH 31, 2011

Report Number and Date	Title	Questioned Costs	Unsupported Costs	Funds Put To Better Use
2009-12651 10/13/2010	Review of TVA's Dam Safety Program	$0	$0	$0
2010-13105 11/10/2010	Stability Assessment Process Review	$0	$0	$0
2010-13571 03/31/2011	Review of TVA's Raccoon Mountain Fire Protection Systems	$0	$0	$0
TOTAL INSPECTIONS (3)		**$0**	**$0**	**$0**

Note: A summary of or link to the full report may be found on the OIG's Web site at www.oig.tva.gov.

Appendix 3

TABLE I | TOTAL QUESTIONED AND UNSUPPORTED COSTS | AUDITS

Audit Reports	Number of Reports	Questioned Costs	Unsupported Costs
A. For which no management decision has been made by the commencement of the period	0	$0	$0
B. Which were issued during the reporting period	2	$4,846,098	$523
Subtotal (A+B)	**2**	**$4,846,098**	**$523**
C. For which a management decision was made during the reporting period	2[1]	$4,846,098	$523
1. Dollar value of disallowed costs	2	$1,303,202	$523
2. Dollar value of costs not disallowed	1	$3,542,896	$0
D. For which no management decision has been made by the end of the reporting period	0	$0	$0
E. For which no management decision was made within six months of issuance	0	$0	$0

[1] *The total number of reports for which a management decision was made during the reporting period differs from the sum of C(1) and C(2) when the same report(s) contain both recommendations agreed to by management and others not agreed to by management.*

TABLE I | TOTAL QUESTIONED AND UNSUPPORTED COSTS | INSPECTIONS

Inspection Reports	Number of Reports	Questioned Costs	Unsupported Costs
A. For which no management decision has been made by the commencement of the period	0	$0	$0
B. Which were issued during the reporting period	0	$0	$0
Subtotal (A+B)	**0**	**$0**	**$0**
C. For which a management decision was made during the reporting period	0	$0	$0
1. Dollar value of disallowed costs	0	$0	$0
2. Dollar value of costs not disallowed	0	$0	$0
D. For which no management decision has been made by the end of the reporting period	0	$0	$0
E. For which no management decision was made within six months of issuance	0	$0	$0

TABLE II | FUNDS TO BE PUT TO BETTER USE | AUDITS

Audit Reports	Number of Reports	Funds To Be Put To Better Use
A. For which no management decision has been made by the commencement of the period	2	$13,695,565
B. Which were issued during the reporting period	5	$24,963,000
Subtotal (A+B)	7	$38,658,565
C. For which a management decision was made during the reporting period	5[2]	$19,815,565
1. Dollar value of recommendations agreed to by management	5	$7,450,161
2. Dollar value of recommendations not agreed to by management	3	$12,365,404
D. For which no management decision has been made by the end of the reporting period	2	$18,843,000
E. For which no management decision was made within six months of issuance	0	$0

[2] The total number of reports for which a management decision was made during the reporting period differs from the sum of C(1) and C(2) when the same report(s) contain both recommendations agreed to by management and others not agreed to by management.

TABLE II | FUNDS TO BE PUT TO BETTER USE | INSPECTIONS

Inspection Reports	Number of Reports	Funds To Be Put To Better Use
A. For which no management decision has been made by the commencement of the period	0	$0
B. Which were issued during the reporting period	0	$0
Subtotal (A+B)	0	$0
C. For which a management decision was made during the reporting period	0	$0
1. Dollar value of recommendations agreed to by management	0	$0
2. Dollar value of recommendations not agreed to by management	0	$0
D. For which no management decision has been made by the end of the reporting period	0	$0
E. For which no management decision was made within six months of issuance	0	$0

Appendix 4

AUDIT AND INSPECTION REPORTS WITH CORRECTIVE ACTIONS PENDING

As of the end of the semiannual period, final corrective actions associated with eight audits and three inspections were not completed within twelve months of the final report date. Presented below for each audit and inspection are the report number and date, a brief description of the open recommendations, and the date management expects to complete final action.

Audit Report Number and Date	Report Title and Recommendation(s) for which Final Action is Not Complete
2007-11216 06/02/2008	**Review of TVA Actions to Protect Social Security Numbers and Eliminate Their Unnecessary Use** TVA agreed to implement protective measures for applications and reports containing social security numbers, such as restricting access and logging downloads. Management expects final action to be completed by August 31, 2011.
2007-11388 08/21/2008	**Sequoyah Nuclear Plant – Cyber Security Assessment** TVA agreed to (1) implement additional device segmentation; (2) use private non-Internet routable IP addresses; (3) evaluate the use of third-party applications; (4) regularly change system passwords; and (5) secure remote access to control systems when this access is necessary. Management expects final action to be completed by September 30, 2011.
2008-11965 02/04/2009	**Contractor Workforce Management (CWM) – Access and General Control Review** TVA is currently undergoing a request for proposal process to either replace or upgrade the existing CWM system. Replacement of the system will remediate the identified vulnerabilities. As of March 31, 2011, TVA was evaluating the proposals.
2008-12127 09/24/2009	**Hydroelectric Plant Automation – General, Physical, and Security Controls Review** TVA agreed to implement the new access control system at all sites and further restrict access to key components. Management expects final action to be completed by June 1, 2013.
2009-12338-05 01/26/2010	**Enterprise Backup and Recovery – Information Systems** TVA agreed to (1) change the process for remote backups by centralizing offsite storage and tape disposal in Chattanooga, procuring additional tape safes for sites and tape vaults in Chattanooga, and instituting a process for securing tapes transmitted from the sites to Chattanooga; and (2) work with the backup software vendor to (a) address partial back-up tracking, (b) search industry best practice, and (c) define requirements. Management expects final action to be completed by September 15, 2011.
2009-12338-07 01/26/2010	**Enterprise Backup and Recovery – Fossil Power Group** TVA agreed to (1) complete documented formal backup and restore procedures and processes for each power plant; (2) establish a repository for critical instruments and controls for each power plant and maintain the repository; (3) develop procedures to inventory, properly store, and test backup media for each power plant; (4) identify processes where reliance for backup is with Information Technology and develop service level agreements to meet backup and restore requirements; and (5) perform periodic backup testing to verify procedures are functional. Management expects final action to be completed by May 27, 2011.
2009-12697 01/25/2010	**Federal Information Security Management Act (FISMA) Evaluation** TVA agreed to improve reporting, monitoring, and remediate security weaknesses, as well as improve efforts to meet remediation due dates. Management expects final action to be completed by August 31, 2011.
2008-12042 01/19/2010	**Distributor Review of Tullahoma Utilities Board** TVA agreed to update the joint cost allocations. Management expects final action to be completed by April 30, 2011.

Appendix 4

AUDIT AND INSPECTION REPORTS WITH CORRECTIVE ACTIONS PENDING *(CONTINUED)*

Inspection Report Number and Date	Report Title and Recommendation(s) for which Final Action is Not Complete
2005-518I 08/31/2005	Review of Physical and Environmental Controls for the Chattanooga Data Center TVA agreed to replace the Chattanooga office complex telephone system with a system operating on the Internet Protocol to eliminate three specific failure modes which could hamper or eliminate TVA's communication ability. Implementation of the new communication system has been delayed by management due to what is considered higher priority projects. Management expects final action to be completed by December 31, 2012.
2008-12007 05/13/2009	Distributor Review of Monroe County Electric Power Authority TVA agreed to (1) consider feasibility of a comprehensive guideline for permissible expenditures, and (2) recommend to the Board that additional financial metrics, including when cash reserves become excessive, be implemented in the rate setting process. Management expects final action to be completed by November 30, 2011.
2008-12040 05/13/2009	Distributor Review of Lewisburg Electric System TVA agreed to (1) consider feasibility of a comprehensive guideline for permissible expenditures, and (2) recommend to the Board that additional financial metrics, including when cash reserves become excessive, be implemented in the rate setting process. Management expects final action to be completed by November 30, 2011.

Appendix 5

INVESTIGATIVE REFERRALS AND PROSECUTIVE RESULTS[1]

Referrals	
Subjects Referred to U.S. Attorneys	22
Subjects Referred to State/Local Authorities	1
Results	
Subject Indicted	1
Subjects Convicted	1
Pretrial Diversion	0
Referrals Declined	19

[1] *These numbers include task force activities and joint investigations with other agencies.*

Appendix 6

HIGHLIGHTS – STATISTICS

	MAR 31, 2011	SEPT 30, 2010	MAR 31, 2010	SEPT 30, 2009	MAR 31, 2009
AUDITS					
AUDIT STATISTICS					
Carried Forward	40	60	44	70	28
Started	29	28	46	46	59
Canceled	3	(7)	(4)	(6)	(3)
Completed	20	(41)	(26)	(66)	(14)
In Progress at End of Reporting Period	46	40	60	44	70
AUDIT RESULTS (Thousands)					
Questioned Costs	$4,846	$2,7130	$980	$6,744	$1,226
Disallowed by TVA	1,303	1,8790	2,255	2,799	829
Recovered by TVA	763	1,921[1]	2,655[2]	909	453[3]
Funds To Be Put To Better Use	$24,963	$13,696	$9,703	$50,570	$0
Agreed to by TVA	7,450	149	8,853	4,723	0
Realized by TVA	12,750[4]	2,091	480	4,395	0
OTHER AUDIT-RELATED PROJECTS					
Completed	13	27	10	16	8
Cost Savings Identified/Realized (Thousands)	$0	$0	$0	$0	$0
INSPECTIONS					
Completed	3	9	2	21	4
Cost Savings Identified/Realized (Thousands)	$0	$0	$0	$0	$0
INVESTIGATIONS[5]					
INVESTIGATION CASELOAD					
Opened	190	199	168	194	171
Closed	161	221	198	223	91
In Progress at End of Reporting Period	199[6]	167	189[7]	251	280
INVESTIGATIVE RESULTS (Thousands)					
Recoveries	$2,144	$36.2	$41.8	$20.6	$10,725.3
Savings	2,515	4,028	0	472.1	0
Fines/Penalties	453	8[8]	5.9	.4	352.7
MANAGEMENT ACTIONS					
Disciplinary Actions Taken (# of Subjects)	7	14	7	6	3
Counseling/Management Techniques Employed (# of Cases)	24	31	25	10	1
Debarment	1[9]				
PROSECUTIVE ACTIVITIES (# of Subjects)					
Referred to U.S. Attorneys	22	51	16	45	18
Referred to State/Local Authorities[10]	1	2	2	6	--
Indicted	1	7	4	3	4
Convicted	1	8	3	3	3
Pretrial Diversion	0	1	2	0	0

[1] *Adjusted to correct amount reported in prior semiannual reports.*
[2] *Ibid.*
[3] *Ibid.*
[4] *Includes $304,036 savings realized in excess of amounts identified in the audits.*
[5] *These numbers include task force activities and joint investigations with other agencies.*
[6] *Adjusted from the previous period.*
[7] *Ibid.*
[8] *Ibid.*
[9] *Category added in semiannual period ended March 31, 2011.*
[10] *Category added in semiannual period ended September 30, 2009.*

Wheeler Dam

Appendix 7

GOVERNMENT CONTRACTOR AUDIT FINDINGS

The National Defense Authorization Act for Fiscal Year 2008, P.L. 110-181, requires each Inspector General appointed under the Inspector General Act of 1978 to submit an appendix on final, completed contract audit reports issued to the contracting activity that contain significant audit findings—unsupported, questioned, or disallowed costs in an amount in excess of $10 million, or other significant findings—as part of the Semiannual Report to Congress. During this reporting period, OIG issued no contract review reports under this requirement.

Appendix 8

PEER REVIEWS OF THE TVA OIG

Audits Peer Review

IG audit organizations are required to undergo an external peer review of their system of quality control at least once every three years, based on requirements in the ***Government Auditing Standards*** (Yellow Book). Federal audit organizations can receive a rating of pass, pass with deficiencies, or fail. During this reporting period, TVA OIG was the subject of a peer review of its audit organization. The review was performed by an ad hoc team appointed by the Council of the Inspectors General on Integrity and Efficiency and led by the U.S. Department of Education (Education) Office of the Inspector General (OIG). Education OIG issued the report, dated March 21, 2011, in which it concluded that the TVA OIG audit organization's system of quality control for the year ended September 30, 2010, was suitably designed and complied with to provide the OIG with reasonable assurance of performing and reporting in conformity with applicable professional standards in all material respects. Accordingly, TVA OIG received a rating of pass. The peer review report is posted on our Web site at http://oig.tva.gov/peer-review.html.

Investigations Peer Review

Investigative operations undergoes an external peer review, Quality Assessment Review (QAR), at least once every three years. During this reporting period, the Office of Personnel Management (OPM) OIG conducted a QAR of the TVA OIG Investigative Operations. The OPM OIG found the "…system of internal safeguards and management procedures for the investigative function of the TVA OIG in effect for the year ending August 1, 2010, is in compliance with the ***Quality Standards for Investigations*** and the Attorney General guidelines. These safeguards and procedures provide reasonable assurance of conforming with professional standards in the conduct of investigations." The QAR report can be found on the TVA OIG Web page at http://oig.tva.gov/peer-review.html.

PEER REVIEW PERFORMED BY THE TVA OIG

As reported in our last semiannual report, TVA OIG led a multi-agency peer review of the investigative operations of the Special Inspector General for Afghanistan Reconstruction (SIGAR). The peer review resulted in a report reflecting ten findings/deficiencies, and lead Inspector General Moore, in his role as CIGIE Chair, Investigations Committee, forwarded the report to the Attorney General for the United States for consideration on whether SIGAR's law enforcement powers should be suspended pending corrective action on the deficiencies.

By request of SIGAR, a remediation or "follow-up" review was conducted at SIGAR's offices in Arlington, Virginia, January 3-5, 2011, by two of the original review team members. The ten findings/deficiencies cited in the initial report were broadly in the areas of a historical lack of policies and procedures (Finding 1), training (Findings 2 through 5), established priorities and planning (Findings 6 and 7), and file/records maintenance (Findings 8 through 10). The findings/deficiencies reflected a lack of conformity to applicable ***Attorney General Guidelines for Offices of Inspector General with Statutory Law Enforcement Authority*** (2003) and President's Council on Integrity and Efficiency/Executive Council on Integrity and Efficiency ***Quality Standards for Investigations*** (December 2003) for at least a significant portion of the review period. The July 2010 Quality Assessment Report is posted on SIGAR's Web site at http://www.sigar.mil/pdf/peer_review/Section5.pdf.

The remediation review resulted in the conclusion that SIGAR has implemented or taken steps to remediate all of the findings contained in the ***Peer Evaluation of the Special Inspector General for Afghanistan Reconstruction Report***. The remedial review did not modify the opinion and conclusions in the original report and did not constitute an external peer review of SIGAR's investigative organization. SIGAR's investigative organization is scheduled to undergo another full scope peer review of their investigations operations in mid 2013.

Glossary

Disallowed Cost | A questioned cost that management, in a management decision, has sustained or agreed should not be charged to the agency.

Final Action | The completion of all management actions, as described in a management decision, with respect to audit findings and recommendations. When management concludes no action is necessary, final action occurs when a management decision is made.

Funds Put To Better Use | Funds, which the OIG has disclosed in an audit report, that could be used more efficiently by reducing outlays, deobligating program or operational funds, avoiding unnecessary expenditures, or taking other efficiency measures.

Management Decision | The evaluation by management of the audit findings and recommendations and the issuance of a final decision by management concerning its response to such findings and recommendations.

Questioned Cost | A cost the IG questions because (1) of an alleged violation of a law, regulation, contract, cooperative agreement, or other document governing the expenditure of funds; (2) such cost is not supported by adequate documentation; or (3) the expenditure of funds for the intended purposes was unnecessary or unreasonable.

Unsupported Costs | A cost that is questioned because of the lack of adequate documentation at the time of the audit.

Abbreviations and Acronyms

The following are acronyms and abbreviations widely used in this report.

ANSI	American National Standards Institute
CEO	Chief Executive Officer
CIGIE	Council of the Inspectors General on Integrity and Efficiency
CWA	Contract Work Authorization
Dam Safety	Dam Safety organization
DHS	Department of Homeland Security
EAPs	Emergency Action Plans
EGC	Enhanced Growth Credit
EIGA	Ethics in Government Act
FISMA	Federal Information Security Management Act
FLETA	Federal Law Enforcement Training Accreditation
FY	Fiscal Year
IG	Inspector General
IT	Information Technology
Kingston Report	Review of Kingston Fossil Plant Ash Spill Root Cause Study and Observations About Ash Management
Marshall Miller	Marshall Miller and Associates, Inc.
OGE	Office of Government Ethics
OIG	Office of the Inspector General
O&M	Operations and Maintenance
OPM	Office of Personnel Management
OSHA	Occupational Safety and Health Administration
SBIR	Small Business Innovation Research
SEC	Securities and Exchange Commission
STTR	Small Business Technology Transfer
TVA	Tennessee Valley Authority
USEPA	U.S. Environmental Protection Agency
WP	Winning Performance
WVDEP	West Virginia Department of Environmental Protection

Office of the Inspector General
400 West Summit Hill Drive
Knoxville, Tennessee 37902

The OIG is an independent organization charged with conducting audits, inspections, and investigations relating to TVA programs and operations, while keeping the TVA Board and Congress fully and currently informed about problems and deficiencies relating to the administration of such programs and operations.

The OIG focuses on (1) making TVA's programs and operations more effective and efficient; (2) preventing, identifying, and eliminating waste, fraud, and abuse and violations of laws, rules, or regulations; and (3) promoting integrity in financial reporting.

If you would like to report to the OIG any concerns about fraud, waste, or abuse involving TVA programs or violations of TVA's Code of Conduct, you should contact the OIG Empowerline system. The Empowerline is administered by a third-party contractor and can be reached 24 hours a day, seven days a week, either by a toll-free phone call (1.877.866.7840) or on the Web (www.oigempowerline.com). You may report your concerns anonymously or you may request confidentiality.

Report Concerns to the OIG Empowerline

EMPOWERLINE™

A confidential connection for reporting fraud, waste or abuse affecting TVA.

HOW TO REPORT A CONCERN

Call toll-free: **877.866.7840**

Or report on the web:
www.OIGempowerline.com

OIG *Leadership* Philosophy

The TVA OIG strives to be a high performing organization made up of dedicated individuals who are empowered, motivated, competent, and committed to producing high quality work that improves TVA and life in the Valley.

Each of us has important leadership, management, team, and technical roles. We value integrity, people, open communication, expansion of knowledge and skills, creative problem solving and collaborative decision making.

Tennessee Valley Authority
Office of the Inspector General

400 West Summit Hill Drive
Knoxville, Tennessee 37902

Office of the Inspector General
Report of Administrative Inquiry

March 23, 2010

William R. McCollum, Jr., LP 6A-C
Ralph E. Rodgers, WT 6A-K

[redacted]
HOLTEC INTERNATIONAL
555 LINCOLN DRIVE WEST
MARLTON, NEW JERSEY 08053
OIG FILE NO. 12E-102

This report was prepared at the request of Ralph E. Rodgers, Deputy General Counsel, Office of the General Counsel, Tennessee Valley Authority (TVA), to summarize investigative and audit efforts concerning the actions of [redacted]. These efforts were initiated following the receipt of a complaint that [redacted] had engaged in funneling money to a TVA employee, John L. (Jack) Symonds, to secure TVA nuclear contracts for HI. This report provides information related to how those payments were made to the TVA employee, [redacted] involvement with those payments and the pattern of behavior exhibited by [redacted] when attempting to acquire nuclear contracts. The report also reflects audit findings of overbilling by HI for equipment costs and the rationale provided by HI and TVA for the price difference at two of TVA's nuclear plants. The findings in this report were based on the statements of [redacted], several witnesses, the statements of Mr. Symonds, former Brown Ferry Nuclear Plant (BFN) Technical Contract Manager, and documents included as attachments.

On August 3, 2007, Mr. Symonds pled guilty in U.S. federal court to making false financial statements to TVA by not disclosing receiving more than $54,000 from Krohn Enterprises LLC, a company he co-owned with his spouse. Mr. Symonds was paid by HI through another company called U. S. Tool & Die (UST&D). Mr. Symonds knew HI had contracted with TVA in November 2001 to design and construct a dry cask storage system for spent nuclear fuel rods at BFN, and had contracted with UST&D to fabricate some of the construction materials for the TVA BFN dry cask storage system. The money received by Mr. Symonds was used to pay personal expenses of Mr. Symonds and his spouse.

OVERVIEW

During June 2000, TVA needed above-ground storage containers to store spent nuclear fuel at Sequoyah Nuclear Plant (SQN). TVA entered into a contract with HI, for design and construction services, storage systems, and the necessary ancillary equipment for the storage containers. During November 2001, the contract was supplemented to authorize HI to perform the same services at BFN. TVA employee Mr. Symonds was involved in the negotiations for the BFN contract as the BFN Technical Contract Manager, while being courted by HI with promises of money and employment. Mr. Symonds was later paid over $50,000 for his assistance in obtaining the TVA contract for HI.

FINDINGS

While TVA was assessing re-racking spent nuclear fuel storage at BFN, the plant initiated a study to determine if BFN should convert to a dry cask storage system instead of re-racking its spent nuclear fuel. Mr. Symonds began advocating strongly for HI to perform the work at BFN that HI had performed at SQN. During this time, [redacted] agreed to pay Mr. Symonds $50,000. [redacted] suggested that Mr. Symonds create a company and took Mr. Symonds to HI's [redacted], who provided Mr. Symonds with a contact which would help Mr. Symonds establish an Limited Liability Company (LLC) in Delaware.

From July 29 to August 2, 2001, Mr. Symonds and his wife went to Philadelphia, Pennsylvania, on a birthday trip. The itinerary for the trip was arranged by HI and the round-trip airline reservation for Mr. Symonds and his wife was made and paid for by HI. From Philadelphia, Mr. Symonds and his wife traveled to Atlantic City, New Jersey, and stayed at the Taj Mahal, the Trump-owned hotel, paid for by HI. Mr. Symonds and his wife had dinner with [redacted] that night. On July 31, 2001, they returned to Philadelphia where HI had made reservations for the Symonds at the Rittenhouse Hotel. [redacted] arranged for a dinner party for the Symonds at a fine French restaurant, Le Bec-Fin, and HI paid $2,137.20 for the meal. Attending were Mr. Symonds and his wife, [redacted] and his wife, and three HI executives and their escorts. [redacted] placed Mr. Symonds at the head of the table.

Later in August, 2001, [redacted] and Mr. Symonds attended a meeting at Fitzpatrick Power Plant, Oswego, New York, consisting of about 30 people representing various utilities to discuss lessons learned. Mr. Symonds was reimbursed a portion of the cost for this trip by TVA, and travel expenses were also charged to UST&D of which [redacted] was the majority owner. A Confidential Source recalled that [redacted] and [redacted] created a company, FABSCO Inc., and that company controlled UST&D (see Attachment 1). While Mr. Symonds was at the meeting, a TVA employee telephoned Mr. Symonds to tell him the TVA Board decided to proceed with the dry

cask storage project for BFN. During a dinner that night, [redacted] announced with fanfare to everyone present the decision to award the BFN work to HI, to the celebratory sound of clinking glasses. During the dinner, Mr. Symonds' wife told [redacted] her vocation was credentialing doctors, which included conducting physicians' background checks.

On September 13, 2001, Mr. Symonds had a breakfast meeting with [redacted] at the Marriott Hotel, Huntsville, Alabama. Previously, [redacted] had discussed employment for Mr. Symonds with HI. During this meeting, [redacted] expressed concern, to avoid appearance problems, that Mr. Symonds not come to work at HI directly from TVA. Mr. Symonds would manage a construction company that appeared to be a separate entity from HI. [redacted] offered Mr. Symonds a vice-president position at HI with a salary of $175,000 per year plus one percent of the business. [redacted] suggested January 1, 2002, as the target date for Mr. Symonds to report to work at HI. Mr. Symonds considered himself a part of HI from that point on, even though he continued to work for TVA. [redacted] told Mr. Symonds they could set up a way to pay Mr. Symonds $50,000 by setting up a business through Mr. Symonds' wife for background investigation services.

During November 2001, the HI dry cask contract for SQN was supplemented to authorize HI to perform the same services at BFN. Mr. Symonds had been involved in the negotiations for the BFN contract as the BFN Technical Contract Manager.

Also in November 2001, Mr. Symonds established Krohn Enterprises, an LLC in Delaware. On December 13, 2001, a post office box was created for Krohn Enterprises, in Huntsville, Alabama, and the name "Jack Symonds" was included as a person with access to the box. A bank account was also created in the name of Krohn Enterprises. Mr. Symonds came up with the name Krohn by using the first two letters of [redacted] first name, [redacted] and the last three letters of his own name, [redacted]

Further, in November 2001, Mr. Symonds and his wife made a house-hunting trip to Philadelphia, Pennsylvania. The trip was later reimbursed by [redacted] through UST&D. During this trip, [redacted] moved Mr. Symonds' employment date from January to April 2002.

Shortly after the meeting in November, Mr. Symonds and [redacted] met at a restaurant in Cherry Hill, New Jersey. [redacted] said he did not know if they were going to bring Mr. Symonds in to HI as a vice president, and said Mr. Symonds might be worth more to [redacted] by remaining at BFN during the Unit 1 restart. [redacted] then said he would pay Mr. Symonds an additional $100,000.

Subsequently, [redacted] instructed UST&D to make a payment of $50,000 to an agency that would be billing UST&D for background checks. No investigative services were rendered to UST&D, and none were provided by Krohn Enterprises. Krohn Enterprises submitted two invoices to UST&D (Attachment 2). The first invoice, dated January 15, 2002, totaled $29,212.77 and included the first "retainer" payment of $25,000 and $4,212.77 in travel expenses. The travel expenses invoiced to UST&D were for the travel expenses of Mr. Symonds' meetings with [redacted] and HI officials. The second invoice, dated February 5, 2002, was for a "retainer fee," payment of $25,000. UST&D paid Krohn Enterprises a total of $54,212.77. A review was conducted of documents obtained by the Office of the Inspector General (OIG) regarding travel by Mr. Symonds and a copy of the review is attached (Attachment 3).

In approximately January 2002, Mr. Symonds learned from TVA employee [redacted], who replaced Mr. Symonds as the Technical Contract Manager for the HI contract, that [redacted] had been offered a job by [redacted] Mr. Symonds did not miss the fact that he was now being ignored by [redacted] while [redacted] was pitching [redacted] to work for him. Mr. Symonds prepared a letter (Attachment 4) and sent it to [redacted] as a last chance for a position with HI, although it was clear to Mr. Symonds that his job with HI was dead.

STATEMENTS BY KRISHNA SINGH

On October 12, 2006, Mr. Symonds consented to telephoning [redacted] for the purpose of recording the conversation. Mr. Symonds told [redacted] the OIG was aware of the money paid to Mr. Symonds by UST&D and was coming to interview Mr. Symonds. Mr. Symonds requested advice from [redacted] on how to handle the situation. [redacted] response was as follows:

> *Well, you know UST&D had hired your wife to do security checks. She got paid for that, right? That was the retainer paid to do the work. She did do retainer work. Why are they auditing your account? There's no, there's nothing that uh, I mean it was a clean transaction, she was in the business of checking out, you know we had some, to my knowledge, UST&D had some problems with thefts and stuff, otherwise it was checks. She paid for, you know they paid for it. But you didn't do any direct business with UST&D, did you? They won't call me because I have nothing to do with it, you know. But to the extent that I pointed to a potential source for UST&D to get the help, they ask me I'll tell them. You know, I'll tell them the straight scoop. Jack you ought to make sure that you tell them that you really have no, the funds you don't know anything about the fact, other than the fact that your wife was in the business of doing consulting services and it was payment retainer for that work, and it's a company that you don't do any business with, and you have not.*

A copy of the entire transcription is attached (Attachment 5).

A few minutes after the recording above was made, [redacted] was interviewed in his office by OIG Special Agents. During that interview [redacted] stated essentially the following.

- Sometime between 1999 and 2001, UST&D was having problems with employee thefts. He wasn't sure if it was parts being stolen or other materials, but there was a problem. [redacted] advised that he mentioned to someone that Mr. Symonds did security checks. He wasn't sure if it was Mr. Symonds, his partner or someone associated with Mr. Symonds that helped companies catch employees stealing. [redacted] may have mentioned the theft problems to Mr. Symonds and suggested Mr. Symonds call the plant manager or he may have mentioned it to plant personnel to contact Mr. Symonds, he just couldn't remember. [redacted] thought he may have put Mr. Symonds in touch with several other people. [redacted] said he could not give the specifics about how he knew Mr. Symonds was involved with catching employees stealing at factories. [redacted] did not know if UST&D used Mr. Symonds or not.

- [redacted] recalled Mr. Symonds visited HI on a couple of occasions when Mr. Symonds was on a project they were doing at BFN. If Mr. Symonds came to HI, he [redacted] would have seen him. He never requested that HI employees entertain Mr. Symonds. However, he did know that Mr. Symonds was friendly with one of HI's engineers who no longer worked for HI. [redacted] was asked if he provided any entertainment to Mr. Symonds and [redacted] said he remembered having dinner with Mr. Symonds on one occasion. He does not remember who paid for the meal but he normally offered to pay for any meal he had with someone and they normally obliged. Sometimes clients would send checks back to him for the cost of their meals. He did not recall the specifics about the meal with Mr. Symonds.

- [redacted] stated that he would not have offered any money to Mr. Symonds or Krohn Enterprises for any reason. He did not direct anyone to pay any money to Mr. Symonds or Krohn Enterprises for any reason. He did not think that Mr. Symonds would solicit money from him. He said he has a particular air about him, and no one would ask a cent from him. [redacted] said that he was a very ethical person in business dealings. [redacted] stated he could not say if someone at HI or UST&D paid Mr. Symonds, but he has never been told anything or that anyone paid Krohn Enterprises anything. [redacted] opined that Mr. Symonds was not in a position to award contracts for TVA.

OTHER BAD ACTS BY [redacted]

[redacted], Exelon Corporation provided documentation relating to an internal investigation concerning an engineer in a position to potentially influence a contract award to HI and whose wife had a business with which HI began doing business under [redacted] direction. That investigation was instituted upon the receipt of information that HI, a contractor involved in a $20,000,000 project with ComEd, an Exelon company, for dry cask storage products, had switched travel agencies and began using an agency in Northbrook, Illinois, called Cove Travel. That travel agency was allegedly owned by [redacted], a Senior Engineer at ComEd Corporate Services, who was involved in administering the project with HI. According to a ComEd Supervising Engineer, in mid-July 1997, while on an audit trip to Japan, a HI Quality Assurance Manager, stated [redacted] had sent a letter to all HI employees instructing all travel arrangements be made through a travel agency in Northbrook. This letter was followed up six months later by [redacted] diverting all travel arrangements to [redacted]). During the internal investigation [redacted] was interviewed concerning the matter and stated he had known [redacted] since late 1989 or early 1990. [redacted] was sure that [redacted] made the initial contact with him relative to Cove Travel. She then submitted a proposal which he turned over to one of the two HI personnel who handled travel arrangements for the firm. He advised that [redacted] had never put pressure on him to use Cove Travel and had never told him he would increase/decrease ComEds business with HI dependent upon the use of Cove Travel. Were this to happen, [redacted] would "kick him out," stating in his mind, for one thing, [redacted] had "zero" authority to place business and had no "clout."

[redacted] WRITES TO INSPECTOR GENERAL AND CHIEF NUCLEAR OFFICER

[redacted] sent a letter addressed to the TVA Inspector General, Richard W. Moore, dated November 17, 2006 (Attachment 6), during the timeframe the criminal investigations were ongoing concerning HI, [redacted] and Mr. Symonds. In that letter [redacted] stated, "Holtec International categorically asserts that the company has not provided any funds to Mr. Saimonds [sic] in any shape or form, indirectly or directly."

[redacted] also e-mailed a letter to Karl Singer, then Chief Nuclear Officer and Executive Vice President, dated November 9, 2006 (Attachment 7). In that letter, [redacted] stated, in part, "… we do not know anything about the gentleman's (Symonds') interactions with UST&D."

CONTRACT REVIEW

The OIG conducted a review of the TVA contract with HI for the purchase of dry cask storage systems for spent nuclear fuel at SQN and BFN. The purpose of the review was to assess the reasonableness of the prices TVA paid HI for certain high-dollar equipment items at BFN in comparison with the prices paid for the equipment at SQN. Specifically, the OIG reviewed the prices TVA paid HI for the four largest dollar-value cask system components: the MPC (multipurpose canister for spent fuel), HI-STORM 100 (long-term storage overpack for the MPC), HI-TRAC 125D (in-plant transfer overpack for the MPC), and the vertical crawler. TVA had paid $7,198,763 for the equipment at SQN, versus $9,186,120 at BFN, a difference of $1,987,357.

Information obtained in the review (Attachment 8) found HI may have made false statements regarding the equipment prices proposed to TVA, and it appeared TVA relied on that information to approve prices quoted for the BFN equipment. Additionally, the review found that HI had overbilled TVA at least $276,000 for the BFN vertical crawler because it did not comply with the contract's cost-plus pricing provision. The price HI quoted for the BFN crawler misrepresented its compliance with the contract.

It appeared TVA relied on the information provided by HI to justify paying the higher BFN prices rather than attempting to negotiate lower pricing for BFN. Although it is unknown if TVA could have successfully negotiated lower prices for BFN, key economic indicators and reduction in material prices between the time period when HI proposed the SQN and BFN prices indicate TVA had an opportunity to negotiate better prices. For example, the price of steel had fallen about seven percent during the period between the SQN proposal and the BFN proposal.

In summary, the OIG review found evidence that the higher prices TVA agreed to pay for the BFN MPC, the HI-STORM 100 and the HI-TRAC 125D were unreasonable. It appears HI may have misled TVA regarding its pricing and TVA did not attempt to negotiate better prices at BFN.

RECOMMENDATIONS

We recommend TVA place HI on the Supply Chain Clearance List based on the actions of (b) (7)(C) [redacted]. In addition, if you decide to take other documented action on the basis of this report, we would appreciate your sending a copy of the relevant information to this office for our file.

We would appreciate being informed within 15 days of your determination of what action is appropriate on the basis of our report. Our investigative files will be made available for review upon request.

This report has been designated "TVA Restricted" in accordance with TVA Business Practice 29, Information Security. Accordingly, it should not be disclosed further without the prior approval of the Inspector General or his designee. In addition, no redacted version of this report should be distributed without notification to the Inspector General of the redactions that have been made.

Our investigation of this matter is closed.

John E. Brennan
Assistant Inspector General
(Investigations)
ET 4C-K

[redacted] (b) (6)
cc: Terrell M. Burkhart, WT 3A-K
Maureen H. Dunn, WT 6A-K
Peyton T. Hairston, Jr., WT 7B-K
Tom D. Kilgore, WT 7B-K
Kenneth E. Tilley, WT 3A-K
OIG File No. 12E-102

2002066-799

PENNSYLVANIA DEPARTMENT OF STATE
CORPORATION BUREAU

Articles of Incorporation-For Profit
(15 Pa.C.S.)

Entity Number

- [X] Business-stock (§ 1306)
- [ ] Business-nonstock (§ 2102)
- [ ] Business-statutory close (§ 2303)
- [ ] Cooperative (§ 7102)
- [ ] Management (§ 2703)
- [ ] Professional (§ 2903)
- [ ] Insurance (§ 3101)

Name
M. BURR KEIM COMPANY
Address
2021 Arch Street
City State Zip Code
Philadelphia, PA 19103

Document will be returned to the name and address you enter to the left.
⇐

Fee: $100

Filed in the Department of State on JUL 25 2002

C. Michael Weaver
Secretary of the Commonwealth

In compliance with the requirements of the applicable provisions (relating to corporations and unincorporated associations), the undersigned, desiring to incorporate a corporation for profit, hereby states that:

1. The name of the corporation *(corporate designator required, i.e., "corporation", "incorporated", "limited" "company" or any abbreviation. "Professional corporation" or "P.C")*:

FABSCO, Inc.

2. The (a) address of this corporation's current registered office in this Commonwealth *(post office box, alone, is not acceptable)* or (b) name of its commercial registered office provider and the county of venue is:

(a) Number and Street	City	State	Zip	County
c/o White and Williams LLP 1800 One Liberty Place	Philadelphia	PA	19103	Philadelphia

Attention: G. P. Biehn, Esq.

(b) Name of Commercial Registered Office Provider — County

c/o:

3. The corporation is incorporated under the provisions of the Business Corporation Law of 1988.

4. The aggregate number of shares authorized: 10,000 shares common

PA001 - 10/01/2001 C T System Online

2002066- 800

DSCB:15-1306,2102/2303/2702/2903/3101/7102A-2

5. The name and address, including number and street, if any, of each incorporator *(all incorporators must sign below)*:

Name	Address
Susan J. Kadin	White and Williams LLP
	1800 One Liberty Place
	Philadelphia, PA 19103

6. The specified effective date, if any: Upon filing
month/day/year hour, if any

7. Additional provisions of the articles, if any, attach an 8½ by 11 sheet.

8. ~~*Statutory close corporation only:* Neither the corporation nor any shareholder shall make an offering of any of its shares of any class that would constitute a "public offering" within the meaning of the Securities Act of 1933 (15 U.S.C. 77a et seq.)~~

9. ~~*Cooperative corporations only. Complete and strike out inapplicable term:* The common bond of membership among its members/shareholders is:~~

IN TESTIMONY WHEREOF, the incorporator(s) has/have signed these Articles of Incorporation to be signed by a duly authorized officer thereof this

25th day of July 2002

Signature
Susan J. Kadin, Incorporator

Signature

PA DOS - 2002 C T System Online

2002066- 801

ARTICLES OF INCORPORATION

FABSCO, INC.

Additional Provisions

7(a). Shareholders shall not have cumulative voting rights in the election of directors.

7(b). The term of the corporation is perpetual.

Doc#: 105395 v5

FROM WHITE & WILLIAMS 2002071 - 971

PENNSYLVANIA DEPARTMENT OF STATE
CORPORATION BUREAU

Articles/Certificate of Merger
(15 Pa.C.S.)

Entity Number
811235

[X] Domestic Business Corporation (§ 1926)
[ ] Domestic Nonprofit Corporation (§ 5926)
[ ] Limited Partnership (§ 8547)

Name
Address CT CORP-COUNTER
City State Zip Code

Document will be returned to the name and address you enter to the left.

Fee: $108 plus $28 additional for each Party in addition to two

Filed in the Department of State on AUG 16 2002

C. Michael Weaver

Secretary of the Commonwealth

In compliance with the requirements of the applicable provisions (relating to articles of merger or consolidation), the undersigned, desiring to effect a merger, hereby state that:

1. The name of the corporation/limited partnership surviving the merger is:
U. S. Tool & Die, Inc.

2. Check and complete one of the following:

[X] The surviving corporation/limited partnership is a domestic business/nonprofit corporation/limited partnership and the (a) address of its current registered office in this Commonwealth or (b) name of its commercial registered office provider and the county of venue is (the Department is hereby authorized to correct the following information to conform to the records of the Department):

(a) Number and Street	City	State	Zip	County
Keystone Commons, 200 Braddock Ave	Turtle Creek	PA	15145	Allegheny

(b) Name of Commercial Registered Office Provider — County
c/o

[ ] The surviving corporation/limited partnership is a qualified foreign business/nonprofit corporation/limited partnership incorporated/formed under the laws of ____________ and the (a) address of its current registered office in this Commonwealth or (b) name of its commercial registered office provider and the county of venue is (the Department is hereby authorized to correct the following information to conform to the records of the Department):

(a) Number and Street — City — State — Zip — County

(b) Name of Commercial Registered Office Provider — County
c/o

[ ] The surviving corporation/limited partnership is a nonqualified foreign business/nonprofit corporation/limited partnership incorporated/formed under the laws of ____________ and the address of its principal office under the laws of such domiciliary jurisdiction is:

Number and Street — City — State — Zip

DSCB:15-1926/5926/8547-2

FROM WHITE & WILLIAMS LLP 2002071- 972 (FRI) 8 16 02 11:51/ST. 11:50/NO. 4862918999 P 3

3. The name and the address of the registered office in this Commonwealth or name of its commercial registered office provider and the county of venue of each other domestic business/nonprofit corporation/limited partnership and qualified foreign business/nonprofit corporation/limited partnership which is a party to the plan of merger are as follows

Name	Registered Office Address	Commercial Registered Office Provider	County
FABSCO, INC	1500 ONE LIBERTY PLACE, PHILADELPHIA, PA 19103		PHILADELPHIA

4. *Check, and if appropriate complete, one of the following*

[X] The plan of merger shall be effective upon filing these Articles/Certificate of Merger in the Department of State

[ ] The plan of merger shall be effective on ______ Date at ______ Hour

5. The manner in which the plan of merger was adopted by each domestic corporation/limited partnership is as follows

Name	Manner of Adoption
FABSCO, Inc.	Board of Directors pursuant to PA BCL1924(b)(1)(ii) & 1924 (b)(3)

6. ~~*Strike out this paragraph if no foreign corporation/limited partnership is a party to the merger.* The plan was authorized, adopted or approved, as the case may be, by the foreign business/nonprofit corporation/limited partnership (or each of the foreign business/nonprofit corporations/limited partnerships) party to the plan in accordance with the laws of the jurisdiction in which it is incorporated/organized.~~

7. *Check, and if appropriate complete, one of the following*

[X] The plan of merger is set forth in full in Exhibit A attached hereto and made a part hereof

[ ] Pursuant to 15 Pa.C.S. § 1901/§ 8547(b) (relating to omission of certain provisions from filed plans) the provisions, if any, of the plan of merger that amend or constitute the operative provisions of the Articles of Incorporation/Certificate of Limited Partnership of the surviving corporation/limited partnership as in effect subsequent to the effective date of the plan are set forth in full in Exhibit A attached hereto and made a part hereof. The full text of the plan of merger is on file at the principal place of business of the surviving corporation/limited partnership, the address of which is

Number and street	City	State	Zip	County

DSCB:15-1926/5926/8547-3

FROM WHITE & WILLIAMS LLP 2002071- 973 (FRI) 8 16'02 11 51/ST 11 50/NO 4862018999 P 4

IN TESTIMONY WHEREOF, the undersigned corporation/limited partnership has caused these Articles/Certificate of Merger to be signed by a duly authorized officer thereof this

14th day of August,

2002.

FABSCO, Inc

Name of Corporation/Limited Partnership

David S Forman

Signature

David S. Forman, President

Title

Name of Corporation/Limited Partnership

Signature

Title

DSCB 15-1926/1926/8547

AUG-16-2002 12:05

Exhibit A

Plan of Merger

This Plan of Merger ("Plan") between FABSCO, Inc., a Pennsylvania corporation ("Parent"), and U.S. Tool & Die, Inc., a Pennsylvania corporation ("Subsidiary") shall be adopted by Parent in the manner and become effective as of the time provided below.

1. Background. Parent is record and beneficial owner of 82.47% of the issued and outstanding capital stock of Subsidiary ("Subsidiary Common Stock"). The remaining shares of the Subsidiary Common Stock are owned and held of record by those shareholders listed in the Subsidiary's corporate records as of the Plan Adoption Date (as such term is defined in Section 2 of this Plan). The Board of Directors of Parent has determined that is desirable and in the best interests of Parent and Subsidiary that Parent be merged with and into the Subsidiary on the terms and conditions set forth in this Plan and in accordance with the applicable provisions of the Pennsylvania Business Corporation Law of 1988, as amended (the "PA BCL").

2. Approval. This Plan shall become adopted ("Plan Adoption Date") upon its approval by the Board of Directors of the Parent in accordance with Sections 1922(c), 1924(b)(1)(ii), and 1924(b)(3) of the PA BCL.

3. Time and Effect of Merger.

(a) *Effective Time*. The Merger shall become effective at the close of business on the date upon which appropriate Articles of Merger (to which this Plan will be attached and incorporated therein) are filed with the Department of State of the Commonwealth of Pennsylvania ("Merger Effective Time").

(b) *Effects of Merger*. At the Merger Effective Time, Parent shall merge with and into Subsidiary, the separate existence of Parent shall cease, and Subsidiary shall be the surviving corporation (the "Surviving Corporation"), all in accordance with this Plan and the applicable provisions of the PA BCL (the "Merger"). At the Merger Effective Time and as a result of the Merger, the Surviving Corporation shall continue to exist as a domestic business corporation under the laws of the Commonwealth of Pennsylvania with all of the rights and obligations of such surviving domestic business corporation as are provided by Section 1929 and the other applicable provisions of the PA BCL. Without limiting the generality of the foregoing, as of the Merger Effective Time, all of the property (real, personal and mixed), rights, powers, privileges, immunities, licenses, permits and franchises (both of a

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private and public nature), and restrictions, duties, and obligations of the Parent and Subsidiary shall be taken and be deemed to be transferred to and vested or continued to be vested, as the case may be, in the Surviving Corporation, without further act, agreement, approval or deed.

4. Articles of Incorporation; Bylaws. The Articles of Incorporation and Bylaws of the Subsidiary as in effect prior to the Merger Effective Time shall remain the same and continue unchanged as, respectively, the Articles of Incorporation and Bylaws of the Surviving Corporation on and after the Merger Effective Time until changed in accordance with their respective terms and the applicable provisions of the PA BCL.

5. Directors and Officers. The Officers of Subsidiary prior to the Merger Effective Time shall, as of the Merger Effective Time, be and remain, respectively, the Officers of the Surviving Corporation until their respective successors are duly elected and qualified under the Bylaws of the Surviving Corporation then in effect, or until their earlier death or until their resignation or removal in accordance with such Bylaws. As of the Effective Time, the Directors of the Surviving Corporation shall be David S. Forman, Robert L. Moscardini and Christopher P. Strock who will serve as Directors of the Surviving Corporation until their respective successors are duly elected and qualified under the Bylaws of the Surviving Corporation then in effect, or until their earlier death or resignation or removal in accordance with such Bylaws.

6. Conversion of Shares.

(a) *Conversion of Shares of Subsidiary*. Subject to the provisions of Sections 7 and 8 of this Plan, except for Dissenting Shares (as such term is defined in Section 10 of this Plan), which at the Merger Effective Time shall be converted into the right to receive the consideration determined in accordance with Section 10 of this Plan and the applicable provisions of the PA BCL, each share of Subsidiary Common Stock shall, at the Merger Effective Time, without further action and by virtue of the Merger, be converted into the right to receive cash consideration in the amount of $ .75 for each share of Subsidiary Common Stock, payable in accordance with Sections 7 and 8 of this Plan, and shall no longer be outstanding and shall be deemed to be automatically canceled and cease to exist.

(b) *Conversion of Shares of Parent*. Subject to the provisions of Section 8 of this Plan, each share of capital stock of Parent ("Parent Shares") shall, at the Merger Effective Time, without further action and by virtue of the Merger, be converted into one (1) share of capital stock of the Surviving Corporation, and shall no longer be outstanding and shall be deemed to be automatically canceled and cease to exist.

7. Withholding Rights. The Surviving Corporation shall be entitled to deduct and withhold from the consideration otherwise payable under Section 6 or 10 of this Plan, as the case may be, such amounts, if any, as it is required to deduct, withhold, and remit with

respect to the making of such payment under any provision of federal, state or local tax law (a "Withholding"). Any such Withholding shall be treated for all purposes (including without limitation this Plan and the Merger) as having been paid to the Record Shareholder (as such term is defined in Section 8) in respect of which the Surviving Corporation made such Withholding and, notwithstanding anything contained to the contrary in this Plan, such Record Shareholder shall only be entitled to receive from the Surviving Corporation the consideration payable pursuant to this Plan and/or the Dissenters' Rights Provisions (as such term is defined in Section 10 of this Plan), less any Withholding, which shall be payable on such Record Shareholder's account to the applicable federal, state or local taxing authority in accordance with applicable federal, state or local tax law ("Net Merger Consideration").

8 Notice; Surrender and Payment; Rights in Subsidiary Common Stock; Etc.

(a) *Merger Notice*. As soon as practicable following the Merger Effective Time, the Surviving Corporation shall mail or cause to be mailed to each record holder or record owner, as the case may be (individually, a "Record Shareholder" and collectively the "Record Shareholders") of the shares of Subsidiary Common Stock on the Plan Adoption Date notices ("Merger Notice") advising them of and enclosing, as applicable: (i) the effectiveness of the Merger, (ii) a copy of this Plan; (iii) a form letter of transmittal and instructions regarding the surrender of their certificates formerly representing shares of Subsidiary Common Stock ("Subsidiary Certificates"), or in lieu thereof, such evidence of lost, stolen or destroyed certificate(s) and such surety bonds or other security as the Surviving Corporation may, in its discretion, require ("Required Documentation"), in exchange for the applicable Net Merger Consideration, and (iv) the notices, information and other materials required to be provided to the Record Shareholders under Section 1575 of the PA BCL.

(b) *Surrender of Subsidiary Certificates; Payment of Consideration*. After the Merger Effective Time, upon surrender of their Subsidiary Certificates, or in lieu thereof, the Required Documentation, to the Surviving Corporation with a properly completed and executed letter of transmittal (substantially in the form included in the Merger Notice) with respect to such certificates, a Record Shareholder will be entitled to receive the applicable Net Merger Consideration. Such consideration shall be delivered by the Surviving Corporation as promptly as practicable after such surrender. Except as otherwise expressly provided in Section 10 of this Plan, without the written consent of a Record Shareholder and such other documentation and other items as the Surviving Corporation in its discretion may require (a "Permitted Substitution"), no person other than a Record Shareholder shall be entitled to receive any consideration whatsoever from the Surviving Corporation as a result of the Merger. In the event of a Permitted Substitution, except in respect of the availability of Dissenters' Rights (as such term is defined in Section 10)), which shall be determined in accordance with Section 10 of this Plan, such person shall be considered a Record Shareholder for purposes of this Plan and the Record Shareholder for which a Permitted Substitution was

made shall thereafter have no right to receive any consideration from the Surviving Corporation as a result of the Merger.

(c) *Rights in Subsidiary Common Stock Following Merger.* As of the Merger Effective Time, (i) the Record Shareholders, all other holders of Subsidiary Certificates, and all beneficial but not record owners of Subsidiary Common Stock prior to the Merger Effective Time, if any, shall cease to have rights with respect to such previously outstanding stock, provided, however that the Record Shareholders only shall have the right to either exchange his, her or its Subsidiary Certificates or Required Documentation, as the case may be, for the Net Merger Consideration to which such Record Shareholder may be entitled pursuant to Sections 6 and 7 of this Plan or elect their Dissenters' Rights in accordance with the Dissenters' Rights Provisions (as such terms are defined in Section 10 of this Plan); and (ii) the Subsidiary Certificates held by Record Shareholders shall be deemed to evidence only ownership of either such Net Merger Consideration or Dissenters' Rights in respect of such Subsidiary Common Stock, if so elected in accordance with the Dissenters' Rights Provisions. In no event shall the Surviving Corporation be obligated to deliver Net Merger Consideration set forth in Sections 6 and 7 or determined pursuant to Section 7 and the Dissenters' Rights Provisions to a Record Shareholder unless and until such Record Shareholder surrenders his, her or its Subsidiary Certificates or furnishes the Required Documentation, as the case may be.

(d) *Surrender of Parent Shares Certificates; Issuance of Surviving Corporation Stock.* Upon receipt by the Surviving Corporation of the certificates representing the Parent Shares or in lieu thereof Required Documentation, as the case may be, together with a properly completed and executed letter of transmittal (in the form acceptable to the Surviving Corporation) with respect to such certificates, the Surviving Corporation will issue to the Parent's shareholders certificates representing the same number of shares of capital stock of the Surviving Corporation as had been held by them in the Parent immediately prior to the Merger Effective Time.

9. Termination of Plan. This Plan may be terminated and the Merger abandoned by action of the Board of Directors of Parent at any time before the Merger Effective Time.

10. Dissenters' Rights. Each (i) Record Shareholder or (ii) subject to compliance with the provisions of Section 1573 of the PA BCL, beneficial owner of Subsidiary Common Stock that is not a Record Shareholder (either, a "Dissenter"), as the case may be, shall be entitled to exercise dissenters' rights ("Dissenters' Rights") with respect to his, her or its shares of Subsidiary Common Stock ("Dissenting Shares") as a result of the Merger, as provided in Sections 1930(a) and 1571 and the other applicable sections of the PA BCL ("Dissenters' Rights Provisions"). Notwithstanding the foregoing, a Dissenter shall forfeit his, her or its Dissenters' Rights, unless such Dissenter makes a demand pursuant to the provisions of Section 1575 of the PA BCL at the time and place specified in the Merger Notice with respect to such shares (a "Perfected Dissenter"). A Perfected Dissenter will be entitled,

subject to compliance with Section 8 of this Plan, to the fair value (less any Withholdings) for his, her or its Dissenting Shares, which fair value will be determined in accordance with Sections 1578 and/or 1579 of the PA BCL, as applicable, and will have such other rights and be subject to such obligations as are accorded to or imposed upon him, her or it pursuant to the Dissenters' Rights Provisions; provided, however, that if a Perfected Dissenter shall subsequently deliver a written withdrawal of his, her or its demand for appraisal of such shares (with the written approval of the Surviving Corporation), then such person shall also forfeit his, her or its Dissenters' Rights. In the event that a Dissenter forfeits his, her or its Dissenters' Rights, then such shares shall thereupon be deemed to have been converted into and to have become exchangeable for, as of the Merger Effective Time, subject to the provisions of Section 8 of this Plan, the right to receive his, her or its Net Merger Consideration provided in Sections 6(a) and 7 of this Plan without any interest or other additional sums payable thereon.

11. Amendment. This Plan may be amended in any manner at any time before the Merger Effective Time by action of the Board of Directors of Parent, subject to compliance with Section 1922(b) of the PA BCL.

The Parent has adopted this Plan as of August 14, 2002.

KROHN ENTERPRISES
PO BOX 5324
HUNTSVILLE, AL
35814-5324
(256) 655-5399

INVOICE

DATE: January 15, 2002
INVOICE # 0001
RE: P.O. 01-12145

Bill To:
US Tool & Die
200 Braddock Avenue
Turtle Creek, PA 15145

For:
Retainer (1/2)
Expenses to Date

DESCRIPTION			AMOUNT
Retainer (½ 1st payment)			25,000.00
Airline Tickets			2,473.50
Hotel			1113.83
Car Rental			413.28
Fuel			39.00
Meals			104.16
Tolls			21.00
Parking			48.00
		TOTAL	$29,212.77

Make all checks payable to **Krohn Enterprises**
Payable upon receipt.

KROHN ENTERPRISES
PO BOX 5324
HUNTSVILLE, AL
35814-5324
(256) 655-5399/5400

INVOIC

DATE: February 15, 2002
INVOICE # 0002
RE: P.O. 01-12145

Bill To:
US Tool & Die
200 Braddock Avenue
Turtle Creek, PA 15145

For:
Retainer (1/2)

DESCRIPTION			AMOUNT
Retainer (½ 2nd payment)			25,000.00
		TOTAL	$25,000.00

Make all checks payable to **Krohn Enterprises**
Payable upon receipt.

Jack Symonds Travel Analysis
Case 12E-100

The following investigation was conducted by Intelligence Analyst (b) (7)(C) [redacted] on August 10, 2006, in Knoxville, TN.

Jul 29-Aug 2, 2001
During the period of 7/29/01 – 8/2/01, Symonds and (b) (7)(C) [redacted] flew to Philadelphia, PA not on duty status. The hotel is suspected to have been paid for by Holtec. TVA was direct-billed for the rental car because Symonds used his government travel card for the rental. TVA was not reimbursed by Symonds. (Title 18, Sec 287).

July 29 – August 2, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Philadelphia, PA	Expense Category	TVA	US Tool & Die	Holtec
Hotel Locations: Atlantic City, NY Philadelphia, PA **On Leave from TVA**	Flight	-	-	Unknown
	Hotel	-	-	$1,176.70
	Rental Car	$244.75	-	Unknown
	Meals	-	-	Unknown
	Gas	-	-	Unknown
	Miscellaneous	-	-	Unknown
	Total	**$244.75**	**$0**	**$1,176.70**

Aug 20 - 26, 2001
During the period of 8/20/01 – 8/26/01, Symonds and (b) (7)(C) [redacted] flew to Syracuse, NY. Symonds' status was on-duty and TVA paid his travel expenses. Subsequently, US Tool & Die also paid for some of his travel expenses through Krohn (Title 18, Sec 209 and 1001).

August 20 – 26, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Syracuse, NY	Expense Category	TVA	US Tool & Die	Holtec
Hotel Locations: Syracuse, NY New York, NY **Not On Leave from TVA**	Flight	$349.00	$349.00	-
	Hotel	$374.64	$374.64	-
	Rental Car	-	-	-
	Meals	$34.32	-	-
	Gas	-	-	-
	Miscellaneous	$186.20	-	-
	Total	**$944.16**	**$723.64**	**$0**

Jack Symonds Travel Analysis
Case 12E-100

Sep 6 - 7, 2001
During the period of 9/6/01 – 9/7/01, Symonds flew to Philadelphia, PA on duty status and TVA paid his travel expenses. Subsequently, US Tool & Die also paid for some of his travel expenses through Krohn Enterprises (Title 18, Sec 209).

September 6 – 7, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Philadelphia, PA	Expense Category	TVA	US Tool & Die	Holtec
Hotel Location: Mount Laurel, NJ Not On Leave from TVA	Flight	$232.50	-	-
	Hotel	$138.71	$138.85	-
	Rental Car	$84.55	$84.55	-
	Meals	$37.48	-	-
	Gas	-	-	-
	Miscellaneous	$74.58	-	-
	Total	$567.82	$223.40	$0

Sep 23 - 30, 2001
During the period of 9/23/01 – 9/30/01, Symonds and [redacted] flew to Allentown, PA, on leave status. TVA was direct-billed for Symonds' rental car because Symonds used his government travel card for the rental (Title 18, Sec 287).

September 23 – 30, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Allentown, PA	Expense Category	TVA	US Tool & Die	Holtec
Hotel Location: Unknown On Leave from TVA	Flight	-	$266.00	-
	Hotel	-	-	-
	Rental Car	$484.44	-	-
	Meals	-	-	-
	Gas	-	$21.80	-
	Miscellaneous	-	-	-
	Total	$484.44	$287.80	$0

Jack Symonds Travel Analysis
Case 12E-100

Oct 7 - 8, 2001
During the period of 10/7/01 – 10/8/01, Symonds flew to Philadelphia, PA during a holiday period. The cost of the flight was direct billed to TVA because Symonds used his government travel card to purchase the ticket, and US Tool & Die, through Krohn, also paid the cost (Title 18, Sec 287 and 1001).

October 7 – 8, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Philadelphia, PA	Expense Category	TVA	US Tool & Die	Holtec
Hotel Location: Mount Laurel, NJ Federal Holiday	Flight	$264.50	$264.50	-
	Hotel	-	$144.56	-
	Rental Car	-	$50.09	-
	Meals	-	-	-
	Gas	-	-	-
	Miscellaneous	-	-	-
	Total	**$264.50**	**$459.15**	**$0**

Nov 9-12, 2001
During the period of 11/9/01 – 11/12/01, Symonds and two friends flew to Baltimore, MD. Symonds rented a car and drove to NJ over a weekend/holiday. Symonds submitted a travel voucher to TVA for reimbursement of expenses, and he also was reimbursed for his airline ticket, hotel, and the rental car by US Tool & Die through Krohn (Title 18, Sec 209 and/or 287).

November 9 – 12, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Baltimore, MD	Expense Category	TVA	US Tool & Die	Holtec
Hotel Location: Mount Laurel, NJ Weekend/Federal Holiday	Flight	$177.50	$177.50	-
	Hotel	$314.82	$314.82	-
	Rental Car	$136.91	$136.91	-
	Meals	$62.04	$14.78	-
	Gas	-	$17.20	-
	Miscellaneous	$43.52	$27.00	-
	Total	**$734.79**	**$688.21**	**$0**

Jack Symonds Travel Analysis
Case 12E-100

Dec 6-7, 2001
During the period of 12/6/01 – 12/7/01, Symonds flew to Philadelphia, PA on duty status, rented a car and traveled to NJ. Symonds submitted a voucher to TVA for reimbursement of expenses and also was reimbursed by US Tool & Die through Krohn (Title 18, Sec 209 and 1001).

December 6 – 7, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Cherry Hill, NJ	Expense Category	TVA	US Tool & Die	Holtec
Hotel Location: Mount Laurel, NJ **Not On Leave from TVA**	Flight	$546.50	$546.50	-
	Hotel	$140.96	$140.96	-
	Rental Car	$102.13	$102.13	-
	Meals	$21.80	$21.74	-
	Gas	-	-	-
	Miscellaneous	$26.52	-	-
	Total	**$837.91**	**$811.33**	**$0**

KROHN ENTERPRISES
PO BOX 5324
HUNTSVILLE, AL
35814-5324
(256) 655-5400

April 1, 2002

[redacted]
Holtec International
Holtec Center
555 Lincoln Drive West
Marlton, NJ 08053

Dear [redacted]

It is becoming more and more difficult for you and I to engage in business conversations, although, through no fault of our own. I am also finding that I too am experiencing some of the paranoid feelings that you have previously expressed concern about. I have determined that the only way to truly communicate with you without fear of some kind of electronic eavesdropping or wiretapping or some other kind of industrial spying technique is to simply revert to a simpler time when writing a letter was the most effective way of communicating. I think that by exercising this medium we can eliminate the anxiety of worrying about what some other people might say or do about the perceptions.

Anyway, I wanted to let you know that the $50K we discussed back in September that was to be paid for activities through the end of the year 2001 has been satisfied. Now let's talk about the $100K that you said that you would pay me in 2002 to stay with TVA. I had originally sent you a proposal that we break that up into quarters which would be $25K in April, $25K in August, $25K in October and $25K in December. You did not respond to that proposal except to say that you wanted me to perform the original deal with Bob. Now that the original deal is satisfied and we are ¼ of the way through 2002, I think we should address how we are going to bill for the remaining $100K.

Krohn Inc. is alive and well and could very well prove to be the proper conduit for this transaction. [redacted] is still the CEO and all business transactions are done through her. If you want, she can send you an RFQ on Krohn Inc. letterhead explaining the billing for services rendered. You think about it and let me know how you want to handle the evolution.

I think that now that the ice has been broken with TVA on a couple of subjects, i.e., Engineering analysis activities with [redacted] and Feedwater Heater issues with [redacted] you should probably offer an unsolicited proposal to perform these kinds of activities. You should address the correspondence to [redacted] and copy [redacted]

[redacted] The only thing is, they might say "come on down and give us a presentation of what you think you can offer". We should be out of the outage by the 10th of April. The bad thing is we are going to do a mid-cycle outage on U2 for 2 identified fuel leakers the last week in April. It will only last a week (we hope). Then the board meets on May 16th to determine the fate of U1. So, if you lay this all out, it looks to me like your best chance at an audience with the decision makers between now and then would be the week of April 15th or the week of May 6th. Plan accordingly.

How is the construction company business search going? Have you told [redacted] not to talk to me? (I thought you may have told them to pretend I didn't exist for a while until some time had passed). I keep trying to get a hold of them and I am not getting any response.

Let's stay in touch, so that we can eliminate any misunderstandings or any miscommunications that we promised each other we would avoid at all cost.

Talk to you later my friend,

(b) (7)(D)

[redacted]

(b) (7)(D)
[redacted]

(b) (7)(D)
[redacted]

(b) (7)(D)

[redacted]

(b) (7)(D)

[redacted]

(b) (7)(D)

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[redacted]

[redacted]

(b) (4)

(b) (4)

[redacted]

July 30, 2007

Charles A. Kandt, ET 4C-K

SPECIAL PROJECT 2007-11160 – HOLTEC INTERNATIONAL CONTRACT NO. 99999906 – REASONABLENESS OF PRICES TVA PAID FOR CERTAIN DRY CASK STORAGE SYSTEMS COMPONENTS AT BROWNS FERRY NUCLEAR PLANT

As requested by OIG Investigative Operations, we initiated an audit of Contract No. 99999906 that TVA has with Holtec International (Holtec) for the purchase of dry cask storage systems for spent nuclear fuel at Sequoyah Nuclear Plant (SQN) and Browns Ferry Nuclear Plant (BFN). The purpose of our review was to assess the reasonableness of the prices TVA paid Holtec for certain high dollar equipment items at BFN in comparison with the prices paid for the equipment at SQN. Specifically, as summarized in the following table, we reviewed the prices TVA paid Holtec for the four largest dollar-value cask system components: (1) the MPC (multipurpose canister for spent fuel); (2) HI-STORM 100 (long-term storage overpack for the MPC); (3) HI-TRAC 125D (in-plant transfer overpack for the MPC); and (4) the vertical crawler.

Summary of Price Differences for Major Components of Dry Cask Storage Systems

Description	SQN Price	BFN Price	Difference
MPC	[redacted]		
HI-STORM 100			
HI-TRAC 125D			
Vertical Crawler			
Total			

Table 1

As discussed in detail below, information obtained in our audit found Holtec may have made false statements regarding the equipment prices proposed to TVA, and it appeared TVA relied on that information to approve prices quoted for the BFN equipment. Additionally, we found that Holtec had overbilled TVA at least $276,000 for the BFN vertical crawler because it did not comply with the contract's cost-plus pricing provision. In our opinion, the price Holtec quoted for the BFN crawler misrepresented its compliance with the contract.

CONTRACT BACKGROUND

On June 30, 2000, TVA entered into Contract No. 99999906 with Holtec to provide equipment and engineering services for a dry cask system to store SQN spent nuclear fuel.[1] On November 8, 2001, the contract was supplemented to include a similar dry cask system for BFN. As of June 20, 2007, the contract had been supplemented 37 times, and TVA had paid Holtec $31.2 million against the contract payment ceiling of $54 million. The contract term is currently set to expire on June 30, 2008.

[1] The original Contract No. P00NNQ-258310 was changed to No. 99999906 in July 2001 for conversion to the PassPort supply chain software.

The contract included fixed prices for most of the components of the cask system and for defined scopes of engineering tasks to address safety aspects of the cask system unique to the two plant sites. The contract also included cost-plus pricing for optional items including (1) construction of a storage pad for the casks at the plant site and (2) a vertical crawler heavy lifting device to move the casks from the plant to the on-site storage pad.

The OIG is investigating certain issues regarding the pricing TVA agreed to under the contract with Holtec. To support the investigation, an audit (Audit 2007-028C) of the contract was initiated to assess the reasonableness of the prices TVA paid Holtec for the four highest dollar cask system components as summarized in Table 1. To perform our review, we:

- Reviewed the contract and related supplements, correspondence, e-mails, and payment records obtained from TVA's files.
- Visited the SQN and BFN sites and interviewed the dry cask spent nuclear fuel project managers and other key personnel to obtain an understanding about the products purchased.
- Obtained copies of TVA's documentation of products received; Holtec's documentation packages for the MPC, HI-STORM 100, and HI-TRAC 125D units as required by the Nuclear Regulatory Commission for these safety-related items; and Holtec's specification document for each crawler, to more clearly define the products purchased.
- Visited Holtec's offices and reviewed cost information to obtain an understanding about Holtec's costs for the products delivered.
- Visited Lift System's (manufacturer of the vertical crawlers) offices and reviewed documentation of sales and related cost data for vertical crawlers sold to Holtec.

AUDIT FINDINGS AND CONCLUSIONS

Information obtained in our audit found Holtec may have made false statements regarding the equipment prices proposed to TVA, and it appeared TVA relied on that information to approve prices quoted for the BFN equipment. Additionally, we found that Holtec had overbilled TVA at least $276,000 for the BFN vertical crawler because it did not comply with the contract's cost-plus pricing provision. In our opinion, the price Holtec quoted for the BFN crawler misrepresented its compliance with the contract.

MPC, HI-STORM 100, and HI-TRAC 125D

Holtec's proposal (dated September 12, 2001) to add the BFN scope of work included significant price increases for the MPC, HI-STORM 100, and HI-TRAC 125D components in comparison to the prices TVA had agreed to pay for similar equipment at SQN. Our review of TVA and Holtec files found Holtec may have made false statements to TVA when it explained why the prices it had quoted for certain BFN components were higher than the SQN prices. Specifically, in a draft letter submitted to TVA, Holtec informed that:

- The HI-STORM 100 for BFN was a significantly improved model in comparison to the model proposed for use at SQN in that (1) it had a reduced height for transport through

Charles A. Kandt
Page 3
July 30, 2007

the plant's external door, and (2) it reduced radiation exposure by about one rem per cask.

- The (lower) SQN price for the HI-TRAC 125D was the result of an arithmetic error during quoting.

Each of these statements appears to be false or at least misleading because:

(1) BFN's external door has an additional 4 feet of vertical clearance in comparison to SQN's, thus negating the need for a reduction in height for the BFN HI-STORM 100,

(2) We found no evidence that the proposed BFN HI-STORM 100 model would have had a significant reduction in radiation dose, and

(3) Holtec initially proposed a price for the SQN HI-TRAC 125D that was the same price subsequently proposed for BFN. The final SQN price resulted from a discount offered by Holtec late in the bidding process. Holtec's claim that the lower SQN price was the result of an arithmetic error rather than a discount may have created the illusion that its prices were not negotiable. (Note – Holtec's final letter transmitting a comparison of the prices did not include the statements from the draft about the HI-STORM 100. However, the letter continued to mislead the TVA negotiation team regarding SQN's low price for the HI-TRAC 125D, referring to it as "an estimating department error.")

It appeared TVA relied on the information provided by Holtec to justify paying the higher BFN prices rather than attempting to negotiate lower pricing for BFN. Although it is unknown if TVA could have successfully negotiated lower prices for BFN, key economic indicators and reductions in material prices between the time period when Holtec proposed the SQN and BFN prices indicate TVA had an opportunity to negotiate better prices. For example, the price of steel had fallen about 7 percent during the period between the SQN proposal and the BFN proposal.

In summary, we found no evidence that the higher prices TVA agreed to pay for the BFN MPC, HI-STORM 100, and HI-TRAC 125D were reasonable. Instead, it appeared (1) Holtec may have misled TVA regarding its pricing, and/or (2) TVA did not attempt to negotiate better prices at BFN.

<u>Vertical Crawler</u>

Contract No. 99999906 provided that the pricing for (b) (4) [redacted] Although the price TVA paid for the SQN crawler was in accordance with the cost-plus provision, the price for the BFN crawler was not. As discussed below, TVA's price for the BFN vertical crawler should have been at (b) (4) [redacted] less than the amount quoted by Holtec. Additionally, since Holtec's price quote for BFN was (b) (4) [redacted] in our opinion the quoted price was a misrepresentation by Holtec that it was complying with the contract's pricing provision.

<u>Holtec's Cost for Vertical Crawler Supplied to BFN</u> – The vertical crawlers provided for SQN and BFN were manufactured and sold to Holtec by Lift Systems. Although the SQN crawler

had been ordered by Holtec specifically for the SQN project, the crawler that was sent to BFN had originally been ordered by Holtec for a project it had with Hope Creek Nuclear Plant (Hope Creek). When TVA requested Holtec to provide a crawler for BFN, to meet TVA's time requirements Holtec apparently requested Lift Systems to (1) send the crawler that had been manufactured for Hope Creek to BFN and (2) manufacture another crawler for Hope Creek.

We reviewed documentation of the prices Holtec paid Lift Systems for each of the crawlers and found Holtec had paid Lift Systems [redacted] Based on the prices Holtec paid for the two vertical crawlers, the most that should have been billable to TVA would have been [redacted][2]

Potential Misrepresentation by Holtec – [redacted] the quoted price misrepresented Holtec's compliance with the contract's cost-plus provision. Additionally, Holtec may have made false statements by informing TVA the price for the BFN crawler was higher than the price of the SQN crawler because the BFN crawler (1) had enhancements that the SQN crawler did not have and (2) included expediting fees. We found the enhancements on the BFN crawler were minor and would not have materially affected Holtec's cost. Additionally, we found no evidence that Holtec incurred any expediting fees other than the higher price it paid Lift Systems for the replacement crawler for Hope Creek.

\- - - - - -

Based on discussions we have had with [redacted] we understand OIG Investigations does not want Audit Operations to issue an audit report to TVA or Holtec at this time since the investigation is ongoing. Accordingly, we are providing the information in this memorandum for use in your ongoing investigation. If you need additional information, please contact [redacted]

Ben R. Wagner
Deputy Inspector General
ET 3C-K

JHB:JP
cc: Jack E. Brennan, ET 4C-K
[redacted]
Richard W. Moore, ET 4C-K
OIG File No. 2007-11160

[2] TVA could make an argument [redacted] However, a legal opinion would be needed as to whether TVA could prevail at paying this lower cost since Holtec apparently had to pay a higher cost to replace the Hope Creek crawler.

Holtec funneled $50,000 to federal employee in bid to win contract, inspector general report says

by Andrew Seidman and Catherine Dunn, Updated: July 9, 2019

TOM GRALISH / STAFF PHOTOGRAPHER

Holtec International, the energy company that in 2014 was awarded $260 million in tax breaks by New Jersey officials to invest in Camden, allegedly funneled tens of thousands of dollars to a manager at a federal agency in an effort to secure a government contract in the early 2000s, according to an inspector general's report cited in a hearing Tuesday.

As Holtec was seeking the contract with the Tennessee Valley Authority in 2001, the company also treated the manager and his wife to a round-trip flight to Philadelphia and stays at the Rittenhouse Hotel and the Trump Taj Mahal in Atlantic City, and a $2,137.20 dinner party at the famed restaurant Le Bec-Fin, according to the report by the federal agency's Office of Inspector General.

RELATED STORIES

- **Jim Walden went after the mob as a federal prosecutor. Now he's investigating N.J. tax breaks.**
- **As tax-credit controversy rages on, Gov. Murphy tours Camden businesses**
- **Norcross-linked firms benefited from behind-the-scenes lobbying on tax breaks, N.J. task force reports**

The manager, John L. Symonds, who worked at an Alabama nuclear plant owned by the TVA, pleaded guilty in 2007 to federal charges related to his failure to disclose $54,000 in income on his financial disclosure forms. The money had been directed to Symonds' company by Holtec, records show.

No one at Holtec was charged with a crime, and the 2010 inspector general's report redacts most of the names associated with Holtec officials. But the report makes reference to "statements by Krishna Singh," the company's CEO, before describing a secretly recorded conversation between Symonds and a Holtec official.

Symonds came up with the name for his company, Krohn Enterprises, by using the first two letters of the Holtec official's first name and the last three letters of his own first name, the report says.

The report was obtained via the Freedom of Information Act by a task force appointed by Gov. Phil Murphy to investigate New Jersey's tax credit programs. Jim Walden, the lead lawyer for the task force, said Tuesday during a hearing in Trenton that Singh's possible involvement in directing payments to the TVA employee should have raised red flags at the state Economic Development Authority before it awarded Holtec tax credits to relocate from Marlton to Camden.

Businesses seeking tax incentives in New Jersey are required to say on their application whether they have ever been prohibited from working as a contractor at a state or federal agency. As ProPublica/WNYC reported in May, Singh falsely certified on Holtec's application that the company had never faced that penalty.

Following the inspector general's investigation, the TVA in 2010 debarred Holtec for 60 days, and the company agreed to pay a $2 million fine. The company has since resumed contracting for TVA.

Holtec, which did not respond to requests for comment Tuesday, denied paying Symonds, according to the report. Holtec has described the failure to report the debarment as an inadvertent oversight. But Walden, the task force special counsel, said the records disclosed Tuesday suggest "Mr. Singh may have played a role in ... or at least at a minimum been aware of" the activity that led to Holtec's debarment as a contractor with the TVA.

The Economic Development Authority is investigating Holtec's tax credits.

Tuesday's hearing marked the first time investigators convened in front of the public since they released a sweeping initial report last month, in which they called out "special interests" as shaping and benefiting from the tax credit legislation, namely the law firm Parker McCay, headed by Philip Norcross, and his brother George E. Norcross III, the Democratic power broker who is executive chairman of the insurance brokerage Conner Strong & Buckelew and sits on the board of Holtec.

Both Parker McCay and Conner Strong, along with several other companies and George Norcross personally, have sued Murphy, claiming the governor created the task force unlawfully. The companies have denied any wrongdoing, and George Norcross said he would be willing to testify in front of a state legislative committee.

A Superior Court judge rejected the companies' bid last month to halt the task force's work during the lawsuit. That decision allowed investigators to publish their first report — which identified more than $500 million in tax credit awards that could be terminated — and set the stage for Tuesday's hearing.

The task force shared the new details about Holtec on a day largely devoted to taking comment from members of the public.

About 40 people spoke over nearly five hours. The testimony was largely split between two camps: Critics of the program, who said it was born of political corruption and benefited “insiders,” and supporters of the credits, including Camden officials and residents, who suggested minor revisions to the program but said the tax credits had helped an impoverished city.

“I don’t know what Holtec may or may not have placed in their application,” said Camden Mayor Frank Moran. But he said it mattered to him that his grandson could study to become an engineer, and have the possibility of getting a good job there one day.

According to the inspector general report on Holtec’s TVA project, a company official had breakfast with Symonds in September 2001 at the Marriott Hotel in Huntsville, Ala. There, the Holtec official told Symonds that the firm could route the $50,000 payment to Symonds by setting up a business for his wife that would offer background check services.

Symonds established Krohn Enterprises in November 2001 as a limited liability company in Delaware, with a post office box in Huntsville. That was the same month that Holtec won the contract to design and construct a storage system for spent nuclear fuel rods at TVA’s Brown’s Ferry Nuclear Plant in Athens, Ala.

Investigators said Holtec funneled the payments through a third company in order to give Krohn $50,000 for background checks. But Krohn never provided those services, according to investigators.

By 2006, federal prosecutors and the TVA’s Office of Inspector General had taken an interest in the payments.

Under the section in the report titled “statements by Krishna Singh,” investigators for the inspector general describe an October 2006 interview with a Holtec official.

The official, whose name is otherwise redacted, told investigators that the subcontractor had been having problems with employee thefts, hence the need for security checks. The official also said “he would not have offered any money to Mr. Symonds or Krohn Enterprises for any reason,” the report says.

The official added that “he was a very ethical person in business dealings.”

During the investigation, Holtec told the inspector general that it “categorically asserts that the company has not provided any funds” to Symonds “in any shape or form, directly or indirectly," according to the report.

A spokesperson for the TVA Office of Inspector General declined to comment on the redactions made to the report except to say they were made under an exemption to Freedom of Information Act law that provides protection for law enforcement information that if disclosed "could reasonably be expected to constitute an unwarranted invasion of personal privacy."

To print the document, click the "Original Document" link to open the original PDF. At this time it is not possible to print the document with annotations.

Posted: July 9, 2019 - 6:32 PM

Andrew Seidman | **@AndrewSeidman** | **aseidman@inquirer.com**

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Trail of Destruction


DAILY NEWS
FARE GAME

By |

Published by
WNYC News

Holtec's $260 Million Tax Break Frozen by NJ EDA

Krishna Singh, right, president and CEO of Holtec International, discusses plans to build a temporary storage site in southeastern New Mexico for spent nuclear fuel on April 29, 2015.
(AP Photo)

Jun 4, 2019 · by **Nancy Solomon** and **Jeff Pillets**

This article was produced in partnership with WNYC, which is a member of the ***ProPublica Local Reporting Network***.

New Jersey state officials have placed a hold on a $260 million tax break for Holtec International, a nuclear company that built its new headquarters on the Camden waterfront, while investigators examine details of its application, according to two state officials with knowledge of the investigation.

Officials took the action after a **report** last month from WNYC and ProPublica about an inaccuracy in a sworn certification submitted by Holtec CEO Kris Singh as part of the company's application. In 2014, the New Jersey Economic Development Authority granted Holtec the second-largest tax break in state history to help the company bring new jobs to the city.

The company collected its first installment, a $26 million tax credit, after moving into its new headquarters in 2017. It would have been eligible for a $26 million credit every year thereafter for nine years. The status of the 2018 credit is not clear. The decision to freeze the credits is the first corrective action by the EDA that has become public since Gov. Phil Murphy started criticizing the program in January.

Holtec is one of a number of companies aligned with South Jersey Democratic boss George E. Norcross III, who serves on its board of directors. Companies linked to Norcross and the law firm of his brother Philip received at least **$1.1 billion** worth of tax breaks, according to a review by WNYC-ProPublica.

Holtec did not respond to a request for comment. After WNYC and ProPublica contacted Holtec about the incorrect information on the application, a lawyer representing Holtec wrote to the EDA, calling the misstatement an "inadvertent mistake" that the company would like to correct. The letter was sent by Kevin Sheehan, an attorney at the law firm Parker McCay, where Philip Norcross is managing partner.

In the sworn statement required for the tax break application, Singh said the company had never been barred from doing business with a state or federal agency, but in 2010, the Tennessee Valley Authority suspended the company for two months and fined it $2 million after a federal investigation found the company had paid a TVA employee $54,212. The employee pleaded guilty to a federal charge of failing to report the

payment on a financial disclosure form. Holtec restored its relationship with the TVA and continues to hold contracts with the agency.

Sheehan handled the applications for many of the companies that received tax breaks to move to Camden. **Emails obtained under a public records request** show that Sheehan and Philip Norcross were involved in rewriting the tax break laws in 2013 that gave special advantages to companies that moved to the city.

George Norcross' insurance company received a tax break to move from the suburbs of Camden into the city. Norcross also sits on the board of Cooper Health System, a nonprofit hospital that received a $39.9 million tax break in 2014.

The New Jersey tax break program is under investigation by the state attorney general and a task force appointed by Murphy. Norcross has hired a phalanx of high-powered attorneys who have filed a lawsuit challenging the task force's authority.

Politico reported this week that the EDA, which administers the program, has received a state grand jury subpoena to provide information about several tax breaks awarded to companies with ties to George Norcross, including his insurance company, Holtec and Cooper Health System, where Philip Norcross also serves on the board.

The tax break for Cooper Health System came under review by the task force during a public hearing in May, when questions were raised about whether the hospital had threatened to move some employees out of state in order to qualify for a larger tax break.

The hospital said it never made such a threat. "Neither the EDA nor the Task Force has provided any document whereby Cooper certified that its jobs were at risk of leaving New Jersey," Thomas Rubino, senior vice president for communications, said in an email to WNYC and ProPublica.

The hospital originally applied for a tax break for office workers to move from the Camden suburbs into the city, where the hospital is located. But in the days before its approval, the EDA asked to see the hospital's out-of-state lease offer, according to emails.

"I am touring alternative locations in Pa. on Wednesday and hope to have term sheets by the end of the week," wrote Andrew Bush, Cooper Hospital's vice president for real estate and facilities. A lease for office space in Philadelphia was later provided to the EDA, and the hospital's tax break was approved four days later.

The EDA staff provided a memo to its board recommending approval, noting that the hospital would otherwise move the jobs to Philadelphia. "The emails related to out-of-state locations were initiated by the EDA, not Cooper," Rubiono wrote. "Cooper did not initiate discussions of alternate locations, nor did it certify it planned to move any jobs out of state. Cooper merely complied with the EDA request for comparable location data."

Two weeks ago, George Norcross, Cooper University Health Care and Parker McCay filed a lawsuit against Murphy and the task force. The complaint, filed in Mercer County Superior Court, argues that George Norcross and his related companies, as well as Parker McCay, have been falsely and publicly accused of misconduct regarding the tax incentives.

The complaint also argues that the governor does not have the authority to investigate the EDA and that task force members are not licensed to practice law in New Jersey.

"Governor Murphy unlawfully empowered the Task Force with powers he did not possess and authorized the retention and payment of New York lawyers who proceeded to commence and conduct an investigation in violation of multiple provisions of New Jersey law," the complaint says.

The task force plans to release its initial findings and recommendations at its third public hearing on June 11.

This report was produced with support from the McGraw Fellowship for Business Journalism at the Craig Newmark School of Journalism, City University of New York.

ProPublica and WNYC are spending the year investigating the power and influence wielded by party bosses in New Jersey's political system. If you know

something about the state's controversial tax incentive program, we'd like to hear from you. We'd particularly like to hear from:

- *Past or present state employees who can tell us about the mechanics of the tax break program*
- *Past or present employees at companies that received tax breaks since 2013 who can tell us about the application process*

If you have something to share with us, here's how to do it:

- *Via email:* ***njwnyc@propublica.org***
- *Via phone call, text. You can also reach us through this number on Signal or WhatsApp, which are more secure: 347-244-2134*
- ***Here's more information*** *on ways to send us documents and other materials.*

2 Comments

Queue

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New Jersey Playbook

Matt Friedman's must-read briefing on the Garden State's important news of the day

Task force uncovers bombshell report on Holtec

By **RYAN HUTCHINS** | 07/10/2019 07:20 AM EDT

Good Wednesday morning. Matt will be back in your inbox tomorrow, and he's back on the job today. Thanks for putting up with my far-less-cutting jokes and puns.

TAXES, TAXES, TAXES: Just when you thought Gov. Phil Murphy's tax incentive task force was about to sit back and listen to the public for a few hours, the panel digs up more dirt on a major tax credit recipient.

We already knew Holtec International CEO and president Krishna P. Singh failed to disclose on his application for $260 million in tax breaks that the company, which makes nuclear reactor parts, had been temporarily barred from working for the federally-owned Tennessee Valley Authority. That much had been uncovered by WNYC and ProPublica, and Holtec admitted the misdirection, calling it "an oversight."

But, it turns out, Singh was personally investigated by the authority's Office of the Inspector General, which convinced an employee there to allow them to secretly record a

call with Singh. The details are all contained in a heavily-redacted OIG report that was read aloud at the task force's hearing yesterday in Trenton.

BRIBE ALLEGATION: The federal official at the authority, John Symonds, was a supervisor at a nuclear plant in Alabama. Symonds told investigators that he was promised a job and given secret payments in exchange for ensuring Holtec landed a contract to build a storage system for spent nuclear fuel rods. He and his wife received more than $54,000 in payments, all funneled through a Holtec subcontractor and then through an LLC called Krohn Enterprises, the report says.

The Krohn name, the OIG report says, was created by using the first two letters of the first name of a Holtec representative, whose identity is redacted, and the last three letters of Symonds' own first name, John.

"**The OIG report found, based on witness testimony**, that this unnamed Holtec representative engaged in the funneling of money to Mr. Symonds and courting him with future employment in order to secure the TVA nuclear contract for Holtec," task force Counsel Jim Walden said during the hearing. "Essentially, the OIG found a bribe."

It's all complicated, messy stuff from more than a decade ago and requires some reading between the lines to understand. Singh, even after a strange, secretly recorded phone call with Symonds, denied any direct ties to the payments to Krohn. But he admitted having dinner with the man and recommending his services to the subcontractor that made the payments.

Walden said the report makes clear Singh "played a role in, or at least at a minimum, had been aware of the underlying activity" involving payments to Symonds. "Certainly the EDA should have conducted greater diligence, because if we were able to obtain this information from both media sources and a FOIA application, certainly the EDA could have done that itself," Walden said.

YOU CAN READ MORE about the issue in a story I wrote with POLITICO's Katherine Landergan, who sat through the hearing as I lounged in an office chair. And you can read the redacted OIG report here. There's more coverage of the hearing below.

DAYS SINCE MURPHY-ALIGNED GROUP INTENTIONALLY BLEW OFF SELF-IMPOSED DEADLINE TO DISCLOSE ITS DONORS: 190

QUOTE OF THE DAY: “Frank is a fair person, a good leader, he gets consensus. But he's not going to be forced by public opinion to move in that direction or to move in this direction." —Rep. Bill Pascrell on his fellow New Jersey Democrat Rep. Frank Pallone

HAPPY BIRTHDAY: POLITICO New Jersey editor **John Appezzato**; Wall Street Journal’s **Heather Haddon;** NJDOLWD’s **David Bander;** Coughlin advisor **Dan Smith**; former Assemblyman **Jack Conners**; BioNJ’s **John Slotman**; Declan O’Scanlon Legislative Director **Beau Huch**; and Andy Kim staffer **Antoinette Miles.**

WHERE’S MURPHY? Signing the New Jersey Land Bank Law in Newark this afternoon.

WHAT TRENTON MADE

TAX MANIA — “Officials, advocates debate merits of tax incentive program,” by POLITICO’s Katherine Landergan: “Public officials and activists debated the merits of New Jersey's tax incentive program at an hourslong hearing on Tuesday, as a task force assembled by Gov. Phil Murphy continues to dig into whether companies improperly took advantage of the incentives. ... Former state Sen. Raymond Lesniak, a Democrat who sponsored the law that created the programs in 2013, gave an impassioned defense of the system and warned that the debate over its effectiveness has become too political. ‘Tax incentives have come under intense criticism, some fair, some unfair, some based on a thoughtful analysis of the program, some based on politics,’ he told the task force. ‘Making the tax incentives debate political is fraught with danger to the economic health of our state.’

“**Sue Altman, the state director of New Jersey Working Families**, said that lawmakers who shepherded the current programs through to passage must be held

accountable. She also refuted the idea that the debate has become too political, saying that the law that created the programs 'was a political bill.' 'This process has brought light to a culture in New Jersey that politics must change,' she said. 'This task force has great significance in New Jersey. It is a mechanism for accountability for all of those involved, at all levels. It must create a road map to prevent corruption in the future."

—"Task force: New Jersey tax incentives law may be unconstitutional," by POLITICO's Ryan Hutchins: "The task force Gov. Phil Murphy appointed to investigate New Jersey's corporate subsidy programs said Tuesday that some aspects of the law underlying the incentives may violate the state's constitution. 'Because portions of the Grow NJ statute were drafted to favor particular parties and disfavor others, we think that there is a very real question as to whether those portions of the statute are unconstitutional,' Jim Walden, the task force's counsel, said during a public hearing in Trenton. 'If the statute does not cross the constitutional line, it comes as close, in our view, as one can imagine,' Walden said."

—"Grieving Camden Council President Jenkins Pleads for Jobs Training to be Part of State Tax Incentives"

—"Jones asks comptroller to investigate Teva EDA award"

ALL ABOUT THAT BASE — "Phil Murphy is starting to act like the NJ version of Donald Trump," The Record's Charles Stile: "As Murphy wades deeper into the quicksand of a Democratic Party civil war, he is waging the fight like a skilled Trumpian. It's as if he got his training at Trump Tower rather than at Goldman Sachs on Wall Street, where he worked for 23 years. Some of Murphy's sharpest foes are quick to taunt him as a Trumpian in progressive clothing. Senate President Stephen Sweeney, D-Gloucester, for example, mocked Murphy for having Trump-like tantrums during last month's budget squabble -- an attacked laced with not a small irony given his political benefactor and insurance executive George Norcross III is a member of Mar-a-lago. Yet, Murphy's use of some of Trump's tactics shows a progressive infused with a more aggressive, do-whatever-it-

takes determination for the long fight ahead. While bashing Trump, Murphy is also learning from him."

VOTER COUNT: The Democratic voter advantage keeps growing in New Jersey and is quickly approaching a million. The latest registration data shows some 963,000 more Democrats than Republicans are registered, an increase of about 67,000 since the November midterms. Out of more than 6,019,844 registered voters, 2,280,845 are Democrats and 1,317,460 are Republicans. Another 2,359,115 are unaffiliated, with the remainder declaring third-party membership.

SWEENEY ON TOUR — "Sweeney pushes Path to Progress at Building Trades Convention," by New Jersey Globe's Nikita Biryukov: "Senate President Steve Sweeney advocated for his path to progress at the Building Trades Convention in Atlantic City Tuesday. 'We are here with the hard working men and women of the trade unions united in our efforts to move New Jersey forward with a strong economy and a state that is affordable for all working families,' Sweeney. 'The work of our brothers and sisters in the building and trades unions is a vital part of an economy that continues to thrive. But we need to bring fiscal responsibility to public finances so that we can make the investments that will expand opportunities for everyone. That can only be accomplished by making the needed reforms from the Path to Progress agenda. It will shape economic growth for our future.'"

TRUMP ERA

PALLONE'S PARTY — "Frank Pallone and Nancy Pelosi sideline the left," by POLITICO's Heather Caygle: "Nancy Pelosi tried to quash Frank Pallone five years ago in a nasty proxy war over the future of the Democratic Caucus. Now, with Pelosi reinstalled as speaker and Pallone chairman of the powerful Energy and Commerce Committee, the

New Jersey Democrat has become a key ally to contain the party's aggressive liberal surge. ‘Frank actually understands we're the majority makers and appreciates what we bring to the table,’ said Rep. Kurt Schrader (D-Ore.), a member of the moderate Blue Dog Coalition who sits on the Energy and Commerce panel. ‘That's very different from 10 years ago when a lot of Blue Dogs were viewed as pariahs.’ Pelosi has spoken openly about protecting the vulnerable Democrats who helped deliver the House last year. And Pallone is essentially the speaker's enforcer at the committee, which is the first real stop for any potential action on progressive priorities like ‘Medicare for All’ and the Green New Deal, H. Res. 109 (116). The partnership is a remarkable turnaround for two onetime opponents.”

—"Malinowski raises $568k for 2nd quarter, has $1 million banked"

—"Christie is draw for Kean Washington fundraiser"

—"Becchi enters GOP House primary vs. Kean"

BOOKER WINS PRESIDENCY *AND* THE GIANTS WIN SUPER BOWL? — "Cory Booker would make NY Giants the New Jersey Giants if elected president," by The Record's Rodrigo Torrejon: “Presidential candidate Senator Cory Booker (D-NJ) claimed that were he to become the commander-in-chief, he'd purposely change the name of the New York Giants to the New Jersey Giants. On the inaugural episode of the ‘Fired Up!’ podcast, hosted by Brad Jenkins, a former White House aide for President Barack Obama, Booker said that he would make a deliberate ‘slip-up’ and call the NFL team the ‘New Jersey Giants,’ joking that nobody would dare impugn his executive authority. ... ‘I’m telling you, when they’re in the White House, I will turn to the world and say — it won’t be a slip of the tongue — I will say, ‘I am proud to be here with the New Jersey Giants.’"

MORE BOOKER — "Pro-Booker super PAC launches effort to reach black voters, but senator still focused on grassroots donations," by NJ Advance Media's Jonathan D. Salant: “The super political action committee created by a former classmate of U.S. Sen. Cory Booker to support his presidential campaign has begun an effort to reach black voters in South Carolina, a state crucial to his chances of winning the 2020 nomination, as well as three other states. And if Booker isn’t the party’s standard-bearer, then the group hopes to turn out those voters for whomever the Democratic nominee is. The goal is to reach 500,000 black voters in Georgia, Mississippi and Maryland in addition to South Carolina.”

—"Six New Hampshire legislators endorse Booker"

IMMIGRATION —"Monmouth, Cape May sheriffs defy NJ AG, extend jail contracts with ICE," by The Record's Monsy Alvarado: "The Monmouth and Cape May county sheriff's departments quietly extended agreements with U.S. Immigration and Customs Enforcement earlier this year, allowing some of their officers to screen jail inmates and flag those in the country illegally for deportation, going against a state attorney general directive that required the sheriffs to get approval for such contract renewals."

— "Murphy AG warns N.J. sheriffs: Don't go behind my back to work with ICE," NJ Advance Media's S.P. Sullivan: "[T]op officials in state Attorney General Gurbir Grewal's office say the county sheriffs violated a directive Grewal issued earlier this year seeking to limit cooperation between New Jersey cops and Immigration and Customs Enforcement. The letters were sent to Monmouth County Sheriff Shaun Golden and Cape May Sheriff Robert Nolan, both Republicans. They highlight the tension between federal authorities in President Donald Trump's administration who have sought to ramp up deportation of unauthorized residents, New Jersey law enforcement officials who want no part of the crackdown and county and local police who remain divided over the issue."

LOCAL

SCREAMING RACIST SAYS RACIST FLYER WAS A HOAX — "'Get out of America!' Racist fight erupts after N.J. town meeting," by NJ Advance Media's Cassidy Grom: "A verbal fight broke out Monday evening in Edison as council members

and residents left the municipal building following a meeting about racist campaign flyers. Christo Makropoulus told political activist Bimal Joshi to 'Get on a plane and get out of America' during the loud expletive-laced argument outside the meeting. ... Makropoulus ... had attended the Committee of the Whole meeting, where councilmen were trying to discover who sent racist flyers during a 2017 Board of Education election. Makropoulus alleged that Patel, Lankey, or their associates sent the flyers themselves. 'They can do their bulls**t where they came from!' he said Monday night. 'Why are they making racial flyers and intimidating the white man?'"

NEWARK LEAD — "Is End in Sight for Lead Lawsuit Against Newark?" by TAPintoNewark's Revecca Panico: "A federal judge has ordered all parties involved in a lawsuit over Newark's lead levels to meet with a mediator, which could mean an early finish in the litigation should a mutually agreed upon resolution be reached. It's been about a year since The Natural Resources Defense Council (NRDC) and Newark Education Workers' Caucus filed its suit, alleging city officials and the state Department of Environmental Protection commissioner violated regulations that caused lead levels to rise. ... The mediation will conclude by Aug. 1 and is closed to the public. Discussions during mediation will remain private unless the matter is resolved."

EVERYTHING ELSE

JUDGING THE JUDGES — "N.J. judge who asked rape victim about closing her legs is sorry, his lawyer says," by NJ Advance Media's Amanda Hoover: "A New Jersey judge who asked a rape victim if she 'knew how to stop somebody from having intercourse with' her and if she could have closed her legs is remorseful for his comments and ready to take a punishment the higher court sees fit, his attorney said. Superior Court Judge John Russo Jr. appeared before the state Supreme Court on Tuesday afternoon for a disciplinary hearing regarding his comments to the rape victim and three other counts of judicial misconduct. Russo did not speak during the 20-minutes of oral arguments; he sat with his hands crossed, twiddling his thumbs. 'He did not intend to imply that a victim of sexual assault should close her legs to avoid' rape, his attorney, Amelia Carolla, told the seven-member Supreme Court. 'He now understands that his intentions do not matter. He understands that what matters only is the impact his words had on others. He is remorseful about the hurt that this may have caused the plaintiff.'"

—"Corrado bill would create sexual assault training for judges"

MEDIA MOVES: Anjalee Khemlani, the managing editor of ROI-NJ, just joined Yahoo Finance, Talking Biz News reports. Khemlani — @AnjKhem — was previously a top editor at NJBIZ before joining Editor Tom Bergeron for the launch of ROI.

ON THE WATERFRONT — "It may take billions to upgrade aging port as rising sea levels threaten coastline, report says," by NJ Advance Media's Ted Sherman: “The modern port system was created in Newark in April 1956, when a refitted oil tanker carrying fifty-eight trailer-sized steel boxes sailed fromNewark to Houston, launching the beginning of container shipping. Most than 60 years later, parts of the port still look much like it did then. And with a huge increase in the amount of cargo now coming into the marine terminals serving the New Jersey and New York region — as well as the impact of global warming on port operations — billions will be needed to remake the waterfront in the coming decades, officials warn. In a new master plan to be released Tuesday, obtained by NJ Advance Media, the Port Authority of New York and New Jersey said while the seaport’s existing facilities vary significantly in age, much of the critical waterside infrastructure was originally constructed before 1950.”

TRANSPORTATION — "New law could give injured NJ Transit workers legal recourse," by The Record's Colleen Wilson: “A legal strategy used by NJ Transit in dozens of pending court cases involving employee injuries — and reinforced by a U.S. Court of Appeals decision in January — may now be toothless thanks to legislation signed into law last month. On June 26, Gov. Phil Murphy signed a bill passed days before by the state Legislature that prohibits NJ Transit from using sovereign immunity in certain situations as a legal defense. The law should help close a loophole that left state rail workers with a limited legal recourse if they had workplace injuries.”

New medical innovations developed in New Jersey will save lives, bring new, more effective medicines to patients, and lower the cost of treatments - all while providing steady incomes for New Jersey workers and a solid, stable economy.

Thank you, Senator Menendez for putting good policy over politics! Learn more: pilma.org/unionjobs/nj

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 24, 2019

EA-18-151

Dr. K. P. Singh
President and CEO
Holtec International
Krishna P. Singh Technology Campus
1 Holtec Boulevard
Camden, NJ 08104

SUBJECT: HOLTEC INTERNATIONAL – NOTICE OF VIOLATION; U.S. NUCLEAR REGULATORY COMMISSION INSPECTION REPORT NO. 07201014/2018-201 DIVISION OF SPENT FUEL MANAGEMENT

Dear Dr. Singh:

This letter refers to the U.S. Nuclear Regulatory Commission (NRC) announced routine inspection at your Holtec International (Holtec) corporate office in Camden, New Jersey from May 14-18, 2018, with continued in-office review through November 26, 2018. The purpose of the inspection was to assess the adequacy of Holtec's activities with regard to the design of spent fuel storage casks with the requirements of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 72, "Licensing Requirements for the Independent Storage of Spent Nuclear Fuel, High-level Radioactive Waste, and Reactor-related Greater Than Class C Waste." Based on the information developed during the inspection, two apparent violations were identified. The circumstances surrounding these apparent violations, the significance of the issues, and the need for lasting and effective corrective actions were discussed with Mr. Mark Soler of your staff during an exit meeting on November 26, 2018. Details regarding the apparent violations were provided in NRC Inspection Report No. 07201014/2018-201, dated November 29, 2018. The inspection report can be found in the NRC's Agencywide Documents Access and Management System (ADAMS) at Accession Number ML18306A853. ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

The letter transmitting the inspection report also provided you with the opportunity to address the apparent violations identified in the report by either: (1) attending a Pre-decisional Enforcement Conference (PEC), or (2) participating in an Alternative Dispute Resolution session before we made our final enforcement decision. In a letter dated December 3, 2018, (ADAMS Accession Number ML18341A126) you requested a pre-decisional enforcement conference.

A PEC was convened at the NRC Headquarters on January 9, 2019, with you and members of your staff to discuss the violations. Subsequent to the PEC, you submitted additional information for the NRC to consider as we proceeded with our enforcement decision process.

The NRC has determined that two violations of regulatory requirements occurred. This determination was based on information developed during the NRC inspection, information you provided in your responses to the inspection report, and information you provided during and after the PEC. The violations are cited in the enclosed Notice of Violation (Notice) and the circumstances surrounding them are described in detail in the subject inspection report (ML18306A853). These violations involved: (1) failure to establish adequate design control measures as a part of the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the functions of the structures, systems, and components which are important to safety as required by 10 CFR 72.146(a), and (2) failure to perform 10 CFR 72.48 evaluations prior to implementing proposed changes and failure to obtain certificate of compliance (CoC) amendments pursuant to 10 CFR 72.244 as required by 10 CFR 72.48.

The failure to establish adequate design control measures and obtain NRC approval prior to modifying multi-purpose canisters (MPC) with four-inch stainless steel stand-off pins, was deemed potentially safety significant. Holtec's design review process for the change did not adequately consider all potential impacts that could adversely affect the safety-related functions of the MPC shims. Impacts not adequately considered included, but are not limited to: MPC handling and manufacturing processes to include peening, lateral loads based on gaps within the MPCs, and conditions adverse to quality identified when personnel discovered defects with the shim stand-off pins during installation. The stand-off pins are essential to the function of the fuel basket to maintain support and ensure that the shims remain in place to allow helium to adequately circulate around the fuel assemblies within the canister.

The MPCs with the shim stand-off pins were not loaded to the full design basis heat load; however, the potential loss of multiple shim stand-off pins in an MPC loaded at the design-basis heat load configuration could have compromised the heat transfer characteristics of the MPC. This could have resulted in an increase in the peak cladding temperature beyond the allowable limit and potentially damage the fuel cladding. Holtec performed a thermal analysis to assess the consequences of the failure of multiple stand-off pins within a MPC and determined that, based on the assumptions used, all predicted results would remain below the described limits in the final safety analysis report with acceptable margin.

NRC staff reviewed the Holtec analysis and concluded that the heat transfer characteristics of the MPCs were adequate and that loaded MPCs would continue to be in a safe condition during the entire licensed period of storage as described in the respective CoC. As a result of this review, the NRC determined that Holtec's violation of 10 CFR 72.48 and 10 CFR 72.146 did not result in an actual significant safety concern. However, the NRC considers Violation 1 to be of moderate safety significance because Holtec's inadequate design control measures did not adequately assess a potentially credible accident and exposure scenario that had the potential for a significant consequence. The failure of multiple stand-off pins in an MPC could have resulted in inadequate heat transfer and the exceedance of peak clad temperature limits. Therefore, this violation has been categorized in accordance with the NRC Enforcement Policy at Severity Level III, in part, because the design change was outside design specifications to the extent that a detailed evaluation was required to determine its operability. The current Enforcement Policy is included on the NRC's website at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html.

Holtec has not been the subject of escalated traditional enforcement action within the last two years or two previous inspections. The NRC did not identify any aggravating circumstances through the course of its enforcement decision process. For mitigating circumstances, the NRC

considered whether credit was warranted for *Corrective Action* in accordance with the civil penalty assessment process in Section 2.3.4 of the Enforcement Policy.

The NRC determined *Corrective Action* credit was warranted due to corrective actions initiated by Holtec. The following are the descriptions of short-term and long-term corrective actions taken. Short-term corrective actions and actions to prevent recurrence for violation 1 included: (1) a root cause evaluation; (2) an analysis of licensees loaded units to ensure they are in safe condition; (3) an analysis of basket shim stand-off for seismic and impact loading; (3) inspection of all non-loaded units to identify necessary actions on a case-by-case basis; (4) elimination of the shim stand-off design from MPC's licensing and fabrication drawings; and (5) notification to customers that have delivered or loaded systems.

Long-term corrective actions included: (1) conducting a lessons learned assessment to cover evaluation of design change from a manufacturing and licensing/analysis standpoint and to address issues within the corrective action program; (2) revising engineering change orders (ECO) and drawing review checklists to include questions on impacts to components during fabrication activities; (3) development of written instructions for process change risk evaluations; (4) development of on-the-job training to include shop tours and review of standard manufacturing processes; (5) evaluation of corrective actions initiated in 2018 for design changes that may not have been appropriately evaluated; (6) development of an ECO surveillance process for technical discipline managers to assess whether design changes were appropriately evaluated; (7) training shop personnel on reviewing travelers and other written instructions prior to performing work; (8) training shop personnel on issues identified with installation of the shims; and (9) evaluating the design change process within technical disciplines to determine areas for improvement.

A base civil penalty in the amount of $36,250 was considered for this Severity Level III violation. However, the staff determined, in accordance with the Enforcement Policy, that a civil penalty for Violation 1 was not warranted. This determination is in recognition of no aggravating circumstances, Holtec's prompt and comprehensive correction of the violation, and the absence of recent escalated enforcement action. This enforcement action may be used in the evaluation of any future significant violations, which could result in a civil penalty. In addition, issuance of the Severity Level III violation constitutes escalated enforcement action that may subject you to increased inspection effort. The NRC includes significant enforcement actions on its Web site at http://www.nrc.gov/reading-rm/doc-collections/enforcement/actions/.

The NRC determined that Violation 2 is a Severity Level IV violation with three examples of failing to follow NRC's requirement to adequately perform a 10 CFR 72.48 evaluation prior to implementing proposed changes and failing to obtain CoC amendments pursuant to 10 CFR 72.244. The violation is described in the subject inspection report and was evaluated in accordance with the NRC Enforcement Policy and resulted in conditions as having very low safety significance. The NRC has determined that escalated enforcement was not warranted for this violation. The violation is cited in the enclosed Notice of Violation (Notice). There is no civil penalty associated with a Severity Level IV violation.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements. In addition, we will follow up your corrective actions during a future NRC inspection.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if any, will be made available electronically for public inspection in the NRC Public Document Room and in ADAMS, accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such information, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). The NRC also includes significant enforcement actions on its Web site at http://www.nrc.gov/reading-rm/doc-collections/enforcememt/actions/).

Should you have any questions, please contact Mr. Christian Araguas at (301) 415-7210 or e-mail (Christian.Araguas@nrc.gov).

Sincerely,

/RA/

George Wilson, Director
Office of Enforcement

Docket Nos. 72-1014, 72-1040,
and 72-1032

Enclosure:
Notice of Violation

SUBJECT: HOLTEC INTERNATIONAL – NOTICE OF VIOLATION; U.S. NUCLEAR REGULATORY COMMISSION INSPECTION REPORT NO. 07201014/2018-201 DIVISION OF SPENT FUEL MANAGEMENT

DOCUMENT DATE: April 24, 2019

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ADAMS Accession No.: ML19072A128 * see previous concurrence

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DATE	04/17/2019	04/17/2019	04/24/2019		

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NOTICE OF VIOLATION

Holtec International
Camden NJ

Docket Nos. 72-1014, 72-1040, 72-1032
EA-18-151

Based on the results of an U.S. Nuclear Regulatory Commission (NRC) inspection conducted at Holtec International (hereafter referred to as Holtec), on May 14, 2018, through July 19, 2018, a team of inspectors identified violations of NRC requirements. In accordance with the NRC Enforcement Policy dated May 15, 2018, the violations are listed below:

Violation 1

10 CFR 72.146(a), "Design control," requires, in part, that measures must be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the functions of the structures, systems, and components which are important to safety.

Contrary to the above, Holtec failed to establish adequate design control measures as a part of the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the functions of the structures, systems, and components which are important to safety. Specifically, on or after August of 2016, Holtec failed to establish adequate design control measures as a part of the selection and review for suitability of application for alternative four-inch stainless steel stand-off pins that were essential to the function of the fuel basket to maintain support and ensure that the shims stay upright to allow helium to adequately circulate around the fuel assemblies within the canister.

This is a Severity Level III violation (NRC Enforcement Policy, Section 6.3.c.1 (b))

Violation 2

A. 10 CFR 72.48(c)(1)(ii)(A), requires, in part, that a certificate holder may make changes in the facility or spent fuel storage cask design as described in the final safety analysis report (FSAR) (as updated), make changes in the procedures as described in the FSAR (as updated), and conduct tests or experiments not described in the FSAR (as updated), without obtaining a CoC amendment submitted by the certificate holder pursuant to § 72.244 (for general licensees and certificate holders) if a change to the technical specifications incorporated in the specific license is not required.

Contrary to the above, as of July 19, 2018, the certificate holder (Holtec) did not obtain a CoC amendment pursuant to § 72.244 for a storage cask design as described in the FSAR despite the fact that the new HI-TRAC VW, Version V design, required a change to the technical specification (TS) incorporated in the CoC. Specifically, Holtec made a change to the HI-TRAC VW design that required new operator actions with new dose rates that affected the FSAR design function and specifications. This change substituted a manual action for an automatic action for performing an FSAR described design function, which would require prior NRC

Enclosure

approval because it would result in more than a minimal increase in the likelihood of occurrence of a malfunction and a change to the TS.

B. 10 CFR 72.48(c)(2)(v), "Changes, tests, and experiments," requires, in part, that a certificate holder shall obtain a CoC amendment pursuant to 10 CFR 72.244 prior to implementing a proposed change, test, or experiment if the change, test, or experiment would create a possibility for a malfunction of a different result than any previously evaluated in the FSAR (as updated).

   Contrary to the above, as of July 19, 2018, the certificate holder (Holtec) did not obtain a CoC amendment when implementing a proposed change that would create a possibility for a malfunction of a different result than any previously evaluated in the FSAR. Specifically, personnel were unable to remove a damaged lift cleat threaded stud from a lifting hole which resulted in three instead of four functional MPC lifting points. Holtec's Hi-Storm 100 FSAR analyzed lifting a fully loaded cask with four lifting lugs.

C. 10 CFR 72.48(d)(1) requires, in part, that the licensee and certificate holder shall maintain records of changes in the facility or spent fuel storage cask design, of changes in procedures, and tests and experiments made pursuant to paragraph (c) of this section. These records must include a written evaluation which provides the bases for the determination that the change does not require a CoC amendment pursuant to paragraph (c)(2) of this section.

   Contrary to the above, as of July 19, 2018, the certificate holder (Holtec) failed to maintain records of changes that included a written evaluation that provided the bases for the determination that the change does not require a CoC amendment pursuant to 10 CFR 72.48(c)(2). Specifically, Holtec failed to perform a written evaluation to demonstrate that a design change for multi-purpose canister stainless steel standoff pins did not require a CoC amendment. Holtec completed a 10 CFR 72.48 screening and incorrectly determined that a written evaluation was not needed.

This is Severity Level IV violation (NRC Enforcement Policy, Section 6.1.d.2).

Pursuant to the provisions of 10 CFR 2.201, Holtec is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555 with a copy to Damaris Marcano, Acting Chief, Inspections and Operations Branch, Division of Spent Fuel Management, Office of Nuclear Material Safety and Safeguards, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level; (2) the corrective steps that have been taken and the results achieved; (3) the corrective steps that will be taken to avoid further violations; (4) your plan and schedule for completing short and long term corrective actions and (5) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or

revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/readingrm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21. If Classified Information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR Part 95. In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days of receipt.

Dated this 24th day of April 2019.

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Monday
Feb042019

Former SNC-Lavalin chief pleads guilty in bribery case

By **Richard L. Cassin** | Monday, February 4, 2019 at 10:08AM

Pierre Duhaime (Image courtesy of Montreal Council on Foreign Relations)Former SNC-Lavalin CEO Pierre Duhaime pleaded guilty Friday to helping a public servant commit breach of trust.

Following his plea, Duhaime, 64, was sentenced to 20 months house arrest and 240 hours of community service.

Fourteen other charges he faced were dropped.

Duhaime was set to go on trial this week for the bribery scandal around construction of a $1.3 billion super-hospital in Montreal.

SNC-Lavalin, Canada's biggest engineering and construction management firm, has been

Aarti Maharaj
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mired for years in allegations of domestic and foreign bribery.

In 2012, the Royal Canadian Mounted Police filed an **affidavit** that tied former SNC-Lavalin executive Riadh Ben Aissa to more than $160 million in alleged bribes paid to Libyan officials in exchange for contracts.

Swiss authorities arrested Ben Aissa and held him for 29 months. They released him as part of a 2014 **plea deal** after he forfeited about $40 million in cash and property.

In 2013, the World Bank **barred** SNC-Lavalin from bank-funded projects for ten years because of alleged corruption in Bangladesh and Cambodia.

In October last year, federal prosecutors in Canada said they **wouldn't negotiate** a remediation agreement with SNC-Lavalin to resolve criminal fraud and corruption charges related to Libya.

Prosecutors charged the company and two subsidiaries for the Libya graft in February 2015.

The board fired Duhaime from his $5 million-a-year CEO post in March 2012. An independent review had discovered he approved $56-million in payments to undisclosed agents.

SNC-Lavalin said in December that "ongoing legal challenges" have caused it to shrink from 20,000 employees in 2013 to 8,500 today.

But it said that since 2012 it has built a world-class ethics and compliance program, cooperated fully with regulatory and government authorities, changed its board, management, and key personnel, and settled class actions in Quebec and Ontario filed on behalf of security holders.

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Richard L. Cassin is editor at large of the FCPA Blog.

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AUGUST 1, 2019 / 7:48 AM / A MONTH AGO

SNC-Lavalin cuts dividend, posts wider-than-expected loss as costs run high

3 MIN READ

(Reuters) - SNC-Lavalin Group Inc (SNC.TO) cut its dividend on Thursday, the latest restructuring effort by the Canadian company, and reported a wider-than-expected loss in its main engineering and construction unit, hit by higher expenses.

FILE PHOTO: A pedestrian walks past the SNC-Lavalin logo outside the company headquarters building in Montreal, Quebec, Canada, May 5, 2019. REUTERS/Dario Ayala

Shares of the Montreal-based company fell as much as 5.6% to more than a 14-year low of C$19.71.

SNC, which named Chief Operating Officer Ian Edwards as interim boss in June, has been trying to turnaround the company after a series of issues, including a bribery allegation that caused a political scandal engulfing Prime Minister Justin Trudeau.

The company's shares have more than halved in value this year, prompting top investor Caisse De Depot Et Placement Du Quebec to call for "decisive and timely action."

TRENDING

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In the last three months, SNC withdrew its 2019 forecast, announced plans to exit fixed price contracts and 15 countries, restructure its business into two reporting lines and explore options for its resources business.

The company said on Thursday that it would now pay a dividend of 2 Canadian cents per share, compared with 10 Canadian cents per share earlier, its second cut in 2019.

SNC maintained its expectations to save about C$100 million in costs by 2019-end.

“This was really (a) tough and disappointing quarter. In my view, however, it also marked a turning point for SNC-Lavalin..” interim Chief Executive Officer Ian Edwards said in a conference call with analysts.

The company’s backlog stood at C$15.7 billion as of June 30, compared with C$15.2 billion a year earlier, while bookings for the second quarter amounted to C$2.1 billion.

SNC posted a net loss attributable to shareholders of C$2.12 billion ($1.60 billion), compared with a year-ago profit of C$83.01 million, as it recorded an about C$1.8 billion goodwill impairment charge related to its resources unit.

Excluding items, the company reported net loss from engineering and construction of C$1.71 per share wider than the C$1.31 estimated by analysts, according to IBES data from Refinitiv.

The company’s SNCL Projects business line, which includes its underperforming resources and engineering, procurement and construction units, posted an operating loss of C$307.7 million, mainly due to higher costs on some of its projects in the Middle East and Canada.

Revenue dropped nearly 10% to C$2.28 billion and also missed estimates of C$2.45 billion.

Reporting by Shanti S Nair in Bengaluru; Editing by Maju Samuel and Shailesh Kuber

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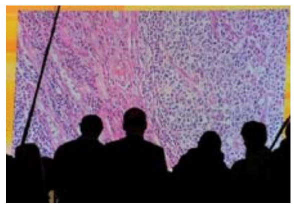

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August 21, 2019

BY ELECTRONIC MAIL
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Assistant General Counsel
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U.S. Nuclear Regulatory Commission
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Plant Licensing Branch III
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555
Scott.Wall@nrc.gov

Re: Pilgrim Nuclear Power Station, NRC Docket Nos. 50-293 & 72-1044 – Objection of the Commonwealth of Massachusetts to Proposed Staff Action on License Transfer Application and Exemption Request

Dear Mr. Campbell and Mr. Wall:

By application dated November 16, 2018 (ADAMS Accession No. ML18320A031) (Application or LTA), Entergy Nuclear Operations, Inc. (Entergy) and Holtec International (Holtec) (collectively, Applicants) requested the transfer of the Renewed Facility Operating License No. DPR-35 for the Pilgrim Nuclear Power Station (Pilgrim) and the general license for Pilgrim's Independent Spent Fuel Storage Installation (ISFSI) from Entergy to Holtec, an unconditioned exemption to use Pilgrim's Decommissioning Trust Fund to pay for site restoration and spent nuclear fuel management costs (incorporated into the LTA by LTA Enclosure 2) (Exemption Request), and a "conforming" amendment to Pilgrim's license to reflect the requested transfer. As part of the state consultation process required by NRC regulations and as discussed with NRC Staff on August 13 and 14, 2019, we are submitting this letter on behalf of the Commonwealth of Massachusetts to object to the NRC Staff's intention to issue an order approving Applicants' license transfer request and Holtec's Exemption Request. Consistent with NRC practice, we also request that NRC Staff include the following response in the State Consultation Section of its Safety Evaluation Report (SER).

At the outset, the Commonwealth objects to the proposed action based on the procedural irregularities and disparate treatment of the Commonwealth during the consultation process as compared to other similarly situated states. On August 13, 2019, the NRC State liaison contacted the Massachusetts Executive Office of Energy and Environmental Affairs with an offer for NRC Staff to consult with the Commonwealth about the Staff's proposed actions during a narrow two-hour window later that day. By mutual agreement, that "consultation" meeting was scheduled for 1:30 pm on August 13, 2019. Approximately twenty-minutes prior to that meeting, however, NRC Staff filed into the above referenced proceeding a "Notification," which informed the proceeding participants that Staff had notified the Commission that Staff intended to issue an order approving the license transfer application and Exemption Request on or about August 21, 2019.[1] Even though the NRC Staff had not yet consulted with the Commonwealth on that intended action, the Notification also indicated wrongly that NRC Staff had *already* notified the Commonwealth of the proposed actions. During the "consultation" call that *followed* the Notification's filing in the docket, the NRC Staff initially declined even to describe the contents of the just filed public Notification and refused to provide any details regarding what the anticipated approval Order would say or the findings underlying it in the anticipated SER. This conduct is not consistent with the NRC's state consultation requirements under, *inter alia*, 10 C.F.R. § 50.91 or the respect due to a sovereign state that has raised serious concerns about the requested actions. Nor is this a situation where an "emergency" would excuse the Staff's obligation to "make a good faith attempt to consult with" the Commonwealth of Massachusetts before NRC Staff or the Commission acts. *See* 10 C.F.R. § 50.91(b)(4).[2]

In another example of a lack of meaningful consultation, NRC Staff, on August 14, 2019, rejected the Commonwealth's request for fourteen days to provide to Staff the Commonwealth's written views on the proposed action prior to the Staff's taking any final action. Instead, in conflict with the state consultation process with the State of New Jersey for the recent transfer of Oyster Creek Nuclear Generating Station's operating license, NRC Staff informed the Commonwealth that it would have five business days (close of business on August 21, 2019) to offer any written comments to Staff on the intended actions. In support of its request for fourteen days, the Commonwealth had noted during its August 13 and August 14, 2019, conversations with NRC Staff that the Staff had just recently given the State of New Jersey fifteen days from the initial notification of the Staff's intention to approve the Oyster Creek license transfer application to submit an official written response to the Staff's proposed action.[3]

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[1] Notification of Significant Licensing Action (NSLA) (ADAMS Accession No. ML19225D006).

[2] The NRC Staff also argued that its obligation to consult with the Commonwealth was limited to the *conforming amendment* sought by the Applicants. The NRC requirements, however, do not so narrowly limit the state consultation process, and, in any event, NRC Staff's approach would undermine the very purpose of state consultation to solicit state input about the *substance* of proposed NRC actions that have the potential to pose environmental and public health risks to the state and its residents.

[3] *Safety Evaluation by the Office of Nuclear Reactor Regulation and Office of Nuclear Material Safety and Safeguards, Related Request for Direct Transfer of Control of Renewed Facility Operating License No. DPR-16 and the General License for the Independent Spent Fuel Storage Installation from Exelon Generation Company, LLC to Oyster Creek Environmental*

Upon receipt of New Jersey's written response, NRC Staff then incorporated New Jersey's written response into the state consultation section of the SER.[4] During its conversations with NRC Staff, the Commonwealth requested that it receive the same treatment as NRC Staff afforded to New Jersey just over two months earlier. After NRC Staff rejected, on August 14, 2019, the Commonwealth's request for fourteen days to submit a written response, the Commonwealth asked NRC Staff whether there were extenuating circumstances that caused the Staff to give New Jersey fifteen days to respond but to reject the Commonwealth's request to be treated similarly. NRC Staff was unable to provide any justification and could not explain why it gave New Jersey fifteen days to respond. Instead, Staff said its internal guidance—Procedures for Handling License Transfers—dictates that Staff is to provide states five business days to respond after initial consultation. Those procedures, however, are silent on the amount of time NRC Staff should give a host state to submit comments on the Staff's intention to approve a license transfer application.[5] NRC Staff's failure to follow what appears to be the NRC's normal state consultation process and its unexplained disparate treatment of the Commonwealth as compared to the State of New Jersey renders its planned action arbitrary and capricious.

Given the NRC Staff's refusal to give the Commonwealth a reasonable amount of time to respond during the consultation process (again, at least the same amount of time it gave New Jersey), the Commonwealth incorporates by reference, as if fully set forth here, the contentions, arguments, and issues it has raised in its yet-to-be acted on Petition for Leave to Intervene and Hearing Request, Docket Nos. 50-293 & 72-1044, filed on February 20, 2019 (Petition); Reply in Support of Petition for Leave to Intervene and Hearing Request, Docket Nos. 50-293 & 72-1044, filed on April 1, 2019 (Reply); and Motion of the Commonwealth of Massachusetts to Supplement Its Petition with New Information, Docket Nos. 50-293 & 72-1044, filed on April 24, 2019. Consistent with the concerns raised in those filings, there are at least two substantive issues that require the NRC Staff to, at a minimum, re-evaluate its plan to approve the license transfer application and Exemption Request if not deny them outright. These two issues go to the heart of this matter—Holtec's ability to satisfy the NRC's financial and technical requirements for license transfer approval—and should make any regulator take the time to

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Protection, LLC and Holtec Decommissioning International, LLC (Oyster Creek Nuclear Generating Station) (Jun. 20, 2019), Docket Nos. 50-219 & 72-15, at 20 (ADAMS Accession No. ML19095A457).

[4] *Id.* at 20.

[5] *See generally U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, NRR Office Instruction, Change Notice: Procedures for Handling License Transfers*, LIC-107, Revision 2 (Jun. 5, 2017) (hereinafter, Procedures for Handling License Transfers). Another Staff action in this matter was, however, inconsistent with the actual terms of that license transfer processing Instruction. While the Instruction provides that NRC Staff must give the *Commission* at least "5 work days" to object to issuance of the Staff approval order before it is issued, *id.* at 13, the Staff sent a notice to Entergy on August 15, 2019, which stated that Pilgrim's license had *already* been "issued to [Holtec]." Encl. at 2 *in* Ltr. from Scott P. Wall, Sr. Project Manager, NRC Plan Licensing Branch III, to Brian R. Sullivan, Site Vice President, Entergy (Aug. 15, 2019) (ADAMS Accession No. ML19191A006). That notice and its statement that the license had already been "issued" to Holtec was then published in the Federal Register on August 20, 2019. 84 Fed. Reg. 43,186, 43,186 col.3 (Aug. 20, 2019).

seriously question and evaluate the veracity of Holtec's assertions, including awaiting the completion of an adjudicatory hearing on them to ensure that all issues have been fully aired and considered.

First, Holtec's response to the NRC Staff's July 26, 2019 Request for Additional Information (RAI) belies any claim that Holtec has satisfied the NRC's financial qualification and assurance requirements for either the license transfer or the Exemption Request. In fact, after Holtec's misleading response to that request is corrected, Holtec's cash-flow analysis shows that Holtec will suffer a funding shortfall of more than $50 million. In its original cash-flow analysis, Holtec claimed a year ending decommissioning trust fund balance of $3.615 million for the year 2063 (projected end of project life).[6] In developing this analysis, Holtec used a license termination cost of $592,553,322.[7] In response to NRC Staff's RAI, Holtec completed a revised cash flow analysis based on the Minimum Formula Amount (MFA), as required by 10 C.F.R. § 50.75(c).[8] The revised MFA-based cash flow analysis increased the license termination cost by $40,714,236 to a total of $633,267,558.[9] Yet, despite the $40 million plus cost increase, and a claim that it used the same assumptions in its revised analysis that it used in its original analysis, Holtec's recent analysis provides a positive year-end trust balance of $11,595,232.[10] In other words, despite increasing its costs, Holtec's analysis results, inexplicably in a higher positive year-end balance. To derive this result in its revised analysis, Holtec appears to have excluded the tax impact on each year-end-earnings-balance that it accounted for in its original cash-flow analysis despite stating to NRC Staff that it included the tax impact.[11] When taxes are accounted for in the revised MFA-based cash-flow analysis, the analysis actually shows a funding shortfall of more than $50 million.

Second, the misleading nature of Holtec's RAI response appears to be part of a troubling pattern of behavior that raises serious questions about Holtec's veracity, judgment, and technical qualifications to decommission a nuclear power reactor. In October 2010, for example, the Tennessee Valley Authority (TVA) temporarily debarred Holtec and required the company to pay a $2 million "administrative fee" based on the results of a criminal investigation into an

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[6] *Revised Post-Shutdown Decommissioning Activities Report and Revised Site-Specific Decommissioning Cost Estimate for Pilgrim Nuclear Power Station*, Enclosure 1, at 47 (Nov. 16, 2018) (ADAMS Accession No. ML18320A040).

[7] *Id.*

[8] *Response to NRC Request for Additional Information*, at E-4-5 and Enclosure (Jul. 29, 2019) (ADAMS Accession No. ML19210E470).

[9] *Id.* Holtec stated that its lower license termination cost estimate is more accurate because it includes site-specific data to Pilgrim, but, as NRC Staff explained in its RAI, Holtec's cash-flow analysis does not comply with the NRC's regulations and, for that reason, cannot be "more accurate." And Holtec's attack on that regulation, of course, constitutes an improper challenge to an NRC regulation. Moreover, a large Boiling Water Reactor, such as Pilgrim, has never been decommissioned in the United States. Additionally, as stated in the Commonwealth's Petition and Reply, Holtec has not provided adequate details as to how its costs are realistic or related to Pilgrim.

[10] *Id.*

[11] *Id.*

alleged Holtec contract-bribery scheme.[12] The TVA employee, who, according to the TVA Inspector General's Report, received $54,000 in undisclosed payments funneled to the employee from Holtec to help Holtec secure a contract with TVA, pleaded guilty in 2007.[13] In a recorded telephone conversation between that employee and an individual who appears in the report to be a Holtec official, during which the employee asked the Holtec official for advice on how to handle the TVA Inspector General's inquiry, the Holtec official informed the employee to tell the investigators that the employee did not "know anything about [the payments], other than the fact that your wife was in the business of doing consulting services and it was a payment retainer for that work."[14] More recently, New Jersey's Economic Development Authority (EDA) froze a $260 million tax break secured by Holtec when it discovered that Holtec had falsely sworn on its tax break application that the company had never "been barred from doing business with a state or federal agency,"[15] even though, as noted above, TVA temporarily debarred Holtec in October 2010. On April 24, 2019, the NRC itself cited Holtec for two violations of NRC regulatory requirements.[16] And, Holtec's business "partner" for its nuclear decommissioning venture, SNC-Lavalin, which Holtec has leaned on heavily to support its claimed technical capacity to undertake multiple complex decommissioning projects at the same time,[17] faces its own legal troubles having been caught-up in numerous alleged international bribery scandals.[18] Of course,

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[12] Office of the Inspector General, TVA, Semiannual Report 18 (Apr. 1, 2015 - Sept. 30, 2015), https://oig.tva.gov/reports/semi59.pdf; *see also* Office of the Inspector General, TVA, Semiannual Report 8 (Oct. 1, 2010 - Mar. 31, 2011), https://oig.tva.gov/reports/semi50.pdf.

[13] Office of Inspector General, TVA, Report of Administrative Inquiry 1 (Mar. 23, 2010), https://www.politico.com/states/f/?id=0000016b-d7ca-d6eb-a96f-fffebfa70001; Andrew Seidman & Catherine Dunn, *Holtec Funneled $50,000 to Federal Employee in Bid to Win Contract, Inspector General Report says*, The Philadelphia Inquirer, Jul. 9, 2019, https://www.inquirer.com/business/holtec-tennessee-valley-authority-nj-tax-credit-investigation-20190709.html.

[14] Office of Inspector General, TVA, Report of Administrative Inquiry 4 (Mar. 23, 2010), https://www.politico.com/states/f/?id=0000016b-d7ca-d6eb-a96f-fffebfa70001.

[15] Nancy Solomon & Jeff Pillets, *Holtec's $260 Million Tax Break Frozen by NJ EDA*, WNYC News, June 4, 2019, https://www.wnyc.org/story/holtecs-260-million-tax-break-frozen-eda/; *see also* Ryan Hutchins, *Task Force Uncovers Bombshell Report on Holtec*, Politico, Jul. 10, 2019, https://www.politico.com/newsletters/new-jersey-playbook/2019/07/10/task-force-uncovers-bombshell-report-on-holtec-454824.

[16] Notice of Violation to Holtec International, NRC OE EA 18-51, 2019 WL 2004418 (Apr. 24, 2019) (ADAMS Accession No. ML19072A128).

[17] Applicants' Answer Opposing the Commonwealth's Mot. to Supplement its Petition with New Information at 8 (May 2, 2019); *see also* Holtec Response to NRC Request for Additional Information at Encl., p.2 (Apr. 17, 2019) (ADAMS Accession No. ML19109A177). In its RAI Response, for example, Holtec relies on the size of SNC-Lavalin's workforce to support its assertion that it will have adequate support for its planned multi-reactor decommissioning endeavor, but SNC-Lavalin is currently restructuring its business and reducing its work force. *Compare id.* at E-2*, with, e.g. infra* note 19.

[18] *See, e.g.*, Richard L. Cassin, *Former SNC-Lavalin Chief Pleads Guilty in Bribery Case*, The FPCA Blog, Feb. 4, 2019, https://www.fcpablog.com/blog/2019/2/4/former-snc-lavalin-chief-pleads-guilty-in-bribery-case.html; *SNC-Lavalin Opts for Judge-Only Trial in Corruption*

any serious criminal or regulatory actions taken against Holtec, or its partners or executives, will have the potential of further draining resources and hampering Holtec's ability to perform decommissioning in a timely, safe and fiscally responsible manner.[19]

Those issues would be problematic if Holtec's obligations were limited to Pilgrim. But, as NRC Staff is aware, they are not limited to Pilgrim. In fact, Holtec is planning to embark on an uncharted path of attempting to decommission *six* nuclear power reactors at four different nuclear generating stations in four different states. The unprecedented nature of this endeavor and the cumulative impacts on Holtec's capacity to follow through on those commitments makes this license transfer application and Exemption Request *sui generis* and outside, for that reason alone, the license transfer actions contemplated by the Commission when it adopted its Subpart M Procedures (10 C.F.R. sub. pt. M). Holtec's unprecedented plan exacerbates all of the issues and concerns raised above and in the Commonwealth's Petition, Reply, and Motion to Supplement, and, in connection with the history described above, demands a heightened degree of scrutiny by NRC Staff and the Commission before any final action is taken on the license transfer or Exemption requests. While Holtec may be comfortable attempting to do what has never been done before, that is cold comfort for the Commonwealth and its citizens who have to accept Holtec as its new resident and the risks that accompany it all before the Commonwealth has an opportunity to present its views in an adjudicatory hearing. That concern is made all the worse by the fact that Hotlec has asked the NRC to delete a pre-existing license condition upon which the public and the Commonwealth have relied that requires the Pilgrim licensee to have access to a $50 million contingency fund for, among other things, "safe and prompt decommissioning." Renewed License No. DPR-35 at 4, ¶ J(4). Certainly, these facts preclude any "no significant hazards consideration" finding or reliance on a National Environmental Policy Act categorical exclusion since the proposed action does much more "than [simply] conform the license to reflect the transfer action." 10 C.F.R. § 2.1315. Indeed, granting the requested actions at Pilgrim and the other power stations will materially and significantly increase the risk to public health, safety, and the environment.

* * *

The Commonwealth appreciates the opportunity to provide written comments to NRC Staff about Staff's intention to issue an order approving the license transfer application and Exemption Request. For the reasons noted above and in its prior filings, the Commonwealth does not believe that Holtec has met the NRC's financial and technical qualification

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Case, CBC News, June 28, 2019, https://www.cbc.ca/news/canada/montreal/snc-lavalin-trial-corruption-bribery-judge-1.5193975.

[19] Indeed, as the Commonwealth noted in its Reply in Support of its Motion to Supplement its Petition with New Information at 3 n.4 (May 9, 2019), SNC-Lavalin's legal troubles have had serious consequences for the company. Just recently, in fact, SNC-Lavalin made a dramatic cut to its dividend payments, lost half of its shareholder value this year, and announced a major restructuring and downsizing of its business. *E.g.*, Shanti S. Nair, *SNC-Lavalin Cuts Dividend, Posts Wider-Than-Expected Loss as Costs Run High*, Reuters, Aug. 1, 2019, https://www.reuters.com/article/us-snc-lavalin-results/snc-lavalin-cuts-dividend-posts-wider-than-expected-loss-as-costs-run-high-idUSKCN1UR4FQ.

requirements for license transfer approval. Indeed, the Commonwealth has serious concerns about Holtec's financial and technical capacity to complete the work at Pilgrim. At a minimum, this history requires a heightened degree of scrutiny by the NRC and its Staff. And, for all of these reasons, including the fact that a "no significant hazards determination" would be erroneous in the circumstances of this matter, the Commonwealth requests that the NRC Staff withhold issuance of the license transfer and Exemption Request approvals until the NRC Staff has fully addressed these issues and the Commonwealth has had an opportunity to contest the requested actions in a full hearing before the Commission prior to any NRC Staff action.

Sincerely

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SNC-Lavalin to stand trial on corruption charges, Quebec judge rules

Quebec engineering giant accused of bribing Libyan officials while Gadhafi in power

Jonathan Montpetit · CBC News · Posted: May 29, 2019 10:35 AM ET | Last Updated: May 29

SNC-Lavalin was caught in a political controversy after failing to secure a deferred prosecution agreement, a kind of plea deal that would have seen the firm agree to pay a fine rather than face prosecution. (Christinne Muschi/Reuters)

comments

There is enough evidence against SNC-Lavalin for the engineering corporation to be tried on fraud and bribery charges, a Quebec court judge ruled Wednesday.

SNC-Lavalin spent months lobbying the federal government to avoid finding itself in this position. It hoped to use a new legal mechanism — a deferred prosecution agreement (DPA) — to pay a fine rather than risk conviction.

Those efforts continued even after the head of the federal prosecution service told the company in the fall that no deal was forthcoming.

That helped ignite a major political scandal in Ottawa when the former attorney general, Jody Wilson-Raybould, accused the Prime Minister's Office of pressuring her to arrange a deal for SNC-Lavalin.

Wednesday's court decision, handed down in Montreal, followed an extended preliminary inquiry into accusations that federal prosecutors filed in 2015.

They allege SNC-Lavalin paid around $48 million in bribes to Libyan officials between 2001 and 2011, a violation of the Corruption of Foreign Public Officials Act.

Asked whether a DPA was still possible, federal prosecutor Richard Roy said: 'The director of public prosecutions has made a decision in that regard.' (Jonathan Montpeti/CBC)

Federal prosecutors also allege SNC-Lavalin defrauded a number of Libyan institutions out of $130 million over the same period.

The contents of Wednesday's ruling, as well as evidence that was heard during the preliminary inquiry, is under a publication ban. Justice Claude Leblond had the option of dismissing the charges if he found there was no chance of a conviction.

- **'I will continue to speak up and speak out:' Jody Wilson-Raybould on political life after the Liberals**

In a brief comment at the provincial courthouse in Montreal, prosecutor Richard Roy said he was satisfied with the outcome.

Asked whether a DPA was still possible, Roy said simply: "The director of public prosecutions has made a decision in that regard."

Ongoing legal troubles

The company's activities in Libya have been under the scrutiny of law enforcement officials since the final days of Moammar Gadhafi's dictatorship.

A former SNC-Lavalin executive, Riadh Ben Aïssa, pleaded guilty in Switzerland in 2014 to paying millions of dollars worth bribes to one of Gadhafi's sons.

Stephane Roy, a financial controller at SNC-Lavalin, was also charged with bribing Libyan officals. That case was dismissed when a judge ruled last year that prosecutors were taking too long to move the proceedings forward.

SNC-Lavalin's efforts to avoid a criminal trial ignited a major political scandal in Ottawa when the former attorney general, Jody Wilson-Raybould, accused the Prime Minister's Office of pressuring her to arrange a deal for the corporation. (Justin Tang/Canadian Press)

Another former executive, Sami Bebawi, is scheduled to stand trial in October on accusations he too bribed Libyan officials.

No date has yet been set for SNC-Lavalin's criminal trial. The corporation returns to court June 7, when it will indicate whether it wants a trial by judge or jury.

Reputation, not money

If found guilty, SNC-Lavalin could face a 10-year ban on receiving federal government contracts. Chief executive Neil Bruce has said that outcome would devastate the company, which has struggled since it was enveloped by a series of corruption scandals in 2012.

The corporation lost around $2.2 billion in market value after federal prosecutors announced last fall they would not be offering a DPA.

- **SNC-Lavalin to scale back operations in 15 countries after being 'disappointed' by earnings**

In a statement issued Wednesday, Bruce sought to distance the company's current management team from what happened in Libya while Gadhafi was in power.

Law professor Kenneth Jull weighs in on the decision to prosecute SNC-Lavalin for corruption charges stemming from its dealings in Libya. 5:44

"These charges relate to alleged wrongdoings that took place seven to 20 years ago by certain former employees who left the company long ago," Bruce said.

SNC-Lavalin's price on the Toronto Stock Exchange was down by, $0.91, or just under four per cent by 2:30 p.m. ET Wednesday.

Quebec's economy minister, Pierre Fitzgibbon, said the provincial government was prepared to help the company financially, should the need arise. But he also said that money isn't SNC-Lavalin's biggest problem at the moment.

"The reputation issue is obviously more important for the company. And there my role is limited," said Fitzgibbon, who has pressed Ottawa in the past to offer the company a DPA.

'These charges relate to alleged wrongdoings that took place seven to 20 years ago by certain former employees who left the company long ago,' SNC-Lavalin's president and CEO Neil Bruce said Wednesday. (Paul Chiasson/Canadian Press)

Liberals maintain support for SNC

The new federal justice minister, David Lametti, has so far refused to comment on whether the government is still considering offering SNC-Lavalin a DPA. Legally, he can do so up until there is

a verdict in the criminal case.

Lametti, on Wednesday, maintained his silence on the issue. He said he wanted to ensure his statements did not influence the court proceedings.

But the federal infrastructure minister, François-Philippe Champagne, reiterated the Liberal government's concerns about the damage a criminal trial could cause SNC-Lavalin.

There are few engineering companies in Canada, he said, who have SNC-Lavalin's experience with major infrastructure projects.

Quebec Economy Minister Pierre Fitzgibbon has pushed for SNC-Lavalin to receive a DPA. (Jacques Boissinot/Canadian Press)

"We need to make sure that we have companies like that who can deliver on the projects that we have in Canada," said Champagne, who represents the central Quebec riding of Saint-Maurice—Champlain.

The current legal uncertainty around SNC-Lavalin extends beyond the pending trial on corruption in Libya.

The RCMP has an open investigation into whether senior company officials were aware of illegal payments made to the former head of Canada's Federal Bridge Corporation, Michel Fournier.

He pleaded guilty in 2017 to receiving $2.3 million from an SNC subsidiary between 2001 and 2003. Fournier admitted that, in exchange, he helped the corporation secure a $127-million contract to refurbish Montreal's Jacques Cartier Bridge.

With files from Colin Harris, Dave Seglins and Cathy Senay at the National Assembly in Quebec City