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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

Pursuant to 10 CFR 50.90, PSEG Nuclear LLC (PSEG) hereby requests a revision to the Operating License and Technical Specifications for the Hope Creek Generating Station. In accordance with 10CFR50.91(b)(1), a copy of this submittal has been sent to the State of New Jersey.

The proposed amendment would increase the maximum power level authorized by Section 2.C.(1) of Operating License NPF-57 from 3339 megawatts thermal (MWt) to 3840 MWt, an increase of approximately 15 percent. This request also includes supporting TS changes necessary to implement the increased power level.

PSEG has evaluated the proposed changes in accordance with 10CFR50.91(a)(1), using the criteria in 10CFR50.92(c), and has determined this request involves no significant hazards considerations. A description of the requested changes and information in support of the no significant hazards consideration determination are provided in Attachment 1 to this letter. The marked up Operating License and Technical Specification pages for the proposed changes are provided in Attachment 2.

Attachment 3 contains a Supplement to the Hope Creek Generating Station Environmental Report supporting a finding of no significant impact. PSEG performed an assessment of environmental impacts of the proposed uprate from 3339 MWt up to a maximum of 3952 MWt by comparing the impacts of the uprate to those previously evaluated by the NRC staff in the 1984 Final Environmental Statement (FES) associated with the issuance of the Hope Creek Operating License. The comparisons

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This letter forwards proprietary information in accordance with 10CFR 2.390. The balance of this letter may be considered non-proprietary upon removal of Attachments 4, 6 and 15.

show that the conclusions of the FES and the Environmental Assessment remain valid for operation at 3840 MWt.

The technical bases for this request follows the guidelines contained in the NRC-approved GE Nuclear Energy (GENE) Licensing Topical Reports (LTRs) for extended power uprate (EPU) safety analysis: NEDC-33004P-A, "Constant Pressure Power Uprate," (CLTR); NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1); and NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2). Attachment 4 contains NEDC-33076P, "Safety Analysis Report for Hope Creek Constant Pressure Power Uprate," dated May 2004 (i.e., the Power Uprate Safety Analysis Report (PUSAR)). The PUSAR is a summary of the results of the safety analyses performed for the Hope Creek EPU. The PUSAR contains information which GE considers to be proprietary. GE requests that the proprietary information in this report be withheld from public disclosure in accordance with 10 CFR 9.17(a)(4) and 2.390(a)(4). An affidavit supporting this request is included with Attachment 4. A non-proprietary version of the report is provided in Attachment 12.

Attachment 5 provides a list of completed and currently planned modifications necessary to support EPU. The planned modifications are scheduled to be implemented before restart from the refueling outage currently planned for Fall 2007. The list of modifications is subject to change based on component evaluations currently being performed. The modifications listed in Attachment 5 are planned actions which do not constitute regulatory commitments by PSEG. The modifications listed in Attachment 5 are being implemented in accordance with the requirements of 10 CFR 50.59 and do not require NRC review and approval.

Attachment 6 provides a description of EPU transient testing. PSEG does not plan to conduct large transient testing requiring an automatic scram from high power (e.g., main steam isolation valve (MSIV) closure). The justification for not performing large transient testing is included in Attachment 6. Attachment 6 contains information which GE considers to be proprietary. GE requests that the proprietary information in this report be withheld from public disclosure in accordance with 10 CFR 9.17(a)(4) and 2.390(a)(4). An affidavit supporting this request is included with Attachment 6. A non-proprietary version of the report is provided in Attachment 16.

Attachment 7 contains a summary of actions completed or currently planned to ensure the integrity of the steam dryer at the EPU condition. A report describing the application of the acoustic circuit model to the Hope Creek steam dryer and main steam line geometry is provided in Attachment 18. A report describing the calculation and evaluation of stresses in the steam dryer at Current Licensed Thermal Power is provided in Attachment 19.

Attachment 8 describes actions completed or currently planned to address the potential for increased flow-induced vibration (FIV) during operation at CPPU conditions. PSEG has actively participated in the activities of the BWR Owners Group EPU Committee.

Attachment 9 provides a summary of grid impact studies which demonstrate that the Hope Creek EPU will not have a significant adverse effect on the reliability or operating characteristics of Hope Creek or on the offsite electrical system.

Attachment 10 provides a markup of the review matrices contained in NRC's "Review Standard for Extended Power Uprates," (RS-001) with cross-references to the Hope Creek PUSAR and other documents submitted in support of this request. Attachment 11 provides a markup of the BWR Safety Template Evaluation contained in RS-001.

Attachment 13 provides marked up TS Bases Pages. These pages are being submitted for information only and do not require issuance by the NRC.

Attachment 14 provides a summary of the findings and observations from the PRA Peer Review Certification of the Hope Creek 1999 PRA model with PSEG's response for each item.

PSEG is aware of NRC concerns related to GE's standard methodologies and the lack of recent gamma scan data. Attachment 15 provides a basis for additional conservatism being proposed to address the NRC concerns and a basis for the adequacy of other existing conservatisms in pertinent safety parameters. An operational restriction on the operating limit minimum critical power ratio (OLMCPR) would be implemented as a condition of the EPU License Amendment if the NRC concerns are not satisfactorily resolved prior to NRC approval of the license change request. Attachment 15 contains information which GE considers to be proprietary. GE requests that the proprietary information in this report be withheld from public disclosure in accordance with 10 CFR 9.17(a)(4) and 2.390(a)(4). An affidavit supporting this request is included with Attachment 15. A non-proprietary version of the report is provided in Attachment 17.

PSEG plans to implement extended power uprate before restart from the refueling outage currently planned for Fall 2007. Therefore, to support PSEG's schedule for reload core design and outage planning, PSEG requests that the proposed changes be approved by February 28, 2007, with implementation to be completed within 120 days from startup (Mode 2) following refueling outage RF14.

Should you have any questions regarding this request, please contact Mr. Paul Duke at 856-339-1466.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 11-4-05
(date)

George P. Barnes
George P. Barnes
Site Vice President – Hope Creek

Attachments (19)

1. Description Of The Requested Changes And Information In Support Of The No Significant Hazards Consideration Determination
2. Marked Up Operating License and Technical Specification Pages
3. Supplement to the Hope Creek Generating Station Environmental Report
4. NEDC-33076P, Revision 1, "Safety Analysis Report for Hope Creek Constant Pressure Power Uprate" (Proprietary)
5. Completed and Planned Modifications
6. EPU Transient Testing (Proprietary)
7. Steam Dryer Evaluation
8. Flow Induced Vibration
9. Summary of Grid Impact Studies
10. Markup of RS-001 Technical Area Review Matrices
11 Markup of RS-001 BWR Template Safety Evaluation
12. NEDO-33076, "Safety Analysis Report for Hope Creek Constant Pressure Power Uprate"
13 Markup of TS Bases Pages (Information Only)
14. Summary of 1999 PRA Peer Review Findings and Observations
15. Enclosure 1 to GE-HCGS-EPU-650, Rev. 2, "Margin in GE Analytical Methods Supporting Hope Creek EPU Submittal" (Proprietary)
16. EPU Transient Testing - Non-Proprietary Version
17. Enclosure 2 to GE-HCGS-EPU-650, Rev. 2, "Margin in GE Analytical Methods Supporting Hope Creek EPU Submittal" (Non-Proprietary Version)
18. "Hydrodynamic Loads on Hope Creek Unit 1 Steam Dryer to 200 Hz," CDI Report 05-17, Revision 1, October 2005
19. "Stress Analysis of the Hope Creek Unit 1 Steam Dryer for CLTP," CDI Report No. 05-25 CDI, November, 2005

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USNRC Senior Resident Inspector - HC (X24)

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Attachment 1

LR-N05-0258
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HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

EXTENDED POWER UPRATE

REQUEST FOR CHANGE TO TECHNICAL SPECIFICATIONS
EXTENDED POWER UPRATE

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REQUEST FOR CHANGE TO TECHNICAL SPECIFICATIONS EXTENDED POWER UPRATE

1. DESCRIPTION

The proposed amendment increases the Hope Creek Generating Station (HCGS) licensed thermal power level to 3840 megawatts thermal (MWt), approximately 15% above the current rated thermal power (RTP) of 3339 MWt and 16.6% above the original RTP of 3293 MWt.

NRC approval of the requested increase in reactor thermal power level will allow PSEG to implement operational changes to generate and supply a higher steam flow to the turbine generator. Higher steam flow is accomplished by increasing the reactor power along specified control rod and core flow lines. This increase in steam flow will permit an increase in the electrical output of the plant.

The technical bases for this request follow the guidelines contained in the NRC-approved GE Nuclear Energy (GENE) Licensing Topical Reports (LTRs) for extended power uprate (EPU) safety analysis: NEDC-33004P-A, "Constant Pressure Power Uprate," (CLTR) (Reference 1); NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1) (Reference 2); and NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2) (Reference 3).

The proposed amendment also includes supporting changes to the Operating License and Technical Specifications necessary to implement the increased power level.

2. PROPOSED CHANGE

PSEG is requesting an increase in the maximum authorized power level for Hope Creek from 3339 MWt to 3840 MWt. This represents an increase of approximately 15 percent from the current RTP.

Proposed changes to the Operating License and Technical Specifications are listed in Table 1 with a brief description of the basis for the change. The marked up Facility Operating License and Technical Specification pages are included in Attachment 2.

Table 1
Proposed OL and TS Changes

Section	Proposed Change	Justification
Operating License Condition 2.C.(1)	Change the Maximum Power Level to 3840 MWt	Revised maximum licensed power level based on General Electric (GE) report NEDC-33076P, "Safety Analysis Report for Hope Creek Constant Pressure Power Uprate," [DATE] (i.e., PUSAR - contained in Attachment 4). Refer to PUSAR Section 1.2.1.
Operating License Condition 2.C.(11)	Change the current License Condition to read as follows: The facility shall not be operated with reduced feedwater temperature for the purpose of extending the normal fuel cycle unless analyses supporting such operation are submitted by the licensee and approved by the staff.	The specified value for feedwater temperature (400°F) is not applicable for EPU. Removal will allow reduced feedwater temperature operation to continue for feedwater system maintenance while ensuring that operation with partial feedwater heating to extend the cycle beyond the normal end-of-cycle condition would still be not be permitted without NRC review and approval.
Operating License Condition 2.C.(16)	Add a new License Condition to allow leak rate tests required by Surveillance Requirement 4.6.1.2.a to be considered to be performed per SR 4.0.1, upon implementation of the license amendment approving the proposed EPU, until the next scheduled performance.	The proposed change precludes having to perform these affected leak rate tests before their next scheduled performance solely for the purpose of documenting compliance. This does not supercede that aspect of SR 4.0.1 that governs cases where it is believed that, if the SR were performed, it would not be met. Performance of the leak rate tests merely to document compliance would unnecessarily divert resources, interfere with plant operations, potentially incur additional personnel dose, and would not improve plant safety.
TS 1.35 - RATED THERMAL POWER	Change RATED THERMAL POWER to 3840 MWt	Revised maximum licensed power level based on GE report NEDC-33076P. Refer to PUSAR Section 1.2.1.

Section	Proposed Change	Justification
TS 2.1.1 - THERMAL POWER, Low Pressure, or Low Flow, and the associated Action	Revise the value of the thermal monitoring thresholds to 24%.	The existing 25% of RTP limit for the TS Safety Limit is based on generic analyses, evaluated up to approximately 50% of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100% RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the Safety Limit % RTP basis for EPU conditions is reduced to 24% RTP. Refer to PUSAR Section 9.1.1
Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.a	Revise the APRM Neutron Flux - Upscale, Setdown Trip Setpoint to 14%. Revise the Allowable Value to 19%.	Refer to PUSAR Section 5.3.7 and Table 5-1.
Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.b.1	Revise the APRM Flow-Biased Simulated Thermal Power – Upscale Trip Setpoint to: $\leq 0.57\ (w - \Delta w) + 58\%$. Revise the Allowable Value to: $\leq 0.57\ (w - \Delta w) + 61\%$.	[Note: This proposed TS change assumes NRC approval of changes proposed in PSEG letter LR-N04-0062, "Request for License Amendment: ARTS/MELLLA Implementation," June 7, 2004] Refer to PUSAR Section 5.3.3 and Table 5-1
LCO 3.1.4.1 - Rod Worth Minimizer, Applicability	Revise the value of the thermal power level for required RWM operability to 8.6%	Refer to PUSAR Section 5.3.4 and Table 5-1

Section	Proposed Change	Justification
LCO 3.2.1 - APLHGR, Applicability; LCO 3.2.1 - APLHGR, Action; and SR 4.2.1.a	Revise the Average Planar Linear Heat Generation Rate (APLHGR) RTP thermal monitoring threshold value to 24%	The existing 25% of RTP limit for the LCO Applicability is based on generic analyses, evaluated up to approximately 50% of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100% RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the LCO Applicability for EPU conditions is reduced to 24% RTP. The proposed changes to the Action and SR maintain consistency with the change to the LCO Applicability. Refer to PUSAR Section 9.1.1.
LCO 3.2.3 - MCPR, Applicability; LCO 3.2.3 - MCPR, Action b; and SR 4.2.3.a	Revise the Minimum Critical Power Ratio (MCPR) RTP thermal monitoring threshold value to 24%	The existing 25% of RTP limit for the LCO Applicability is based on generic analyses, evaluated up to approximately 50% of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100% RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the LCO Applicability for EPU conditions is reduced to 24% RTP. The proposed changes to the Action and SR maintain consistency with the change to the LCO Applicability. Refer to PUSAR Section 9.1.1.

Section	Proposed Change	Justification
LCO 3.2.4 - LHGR, Applicability; LCO 3.2.4 - LHGR, Action; and SR 4.2.4.a	Revise the Linear Heat Generation Rate (LHGR) RTP thermal monitoring threshold value to 24%	The existing 25% of RTP limit for the LCO Applicability is based on generic analyses, evaluated up to approximately 50% of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100% RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the LCO Applicability for EPU conditions is reduced to 24% RTP. The proposed changes to the Action and SR maintain consistency with the change to the LCO Applicability. Refer to PUSAR Section 9.1.1.
Table 3.3.1-1 - Reactor Protection System Instrumentation Table Notations, Note (j)	Revise the RTP value to 24%. Remove the values for turbine first stage pressure.	Refer to PUSAR Section 5.3.2 and Table 5-1 for change to RTP value. Modifications to the high pressure turbine will change the relationship of turbine first stage pressure to reactor power. The turbine first stage pressure setpoint will be controlled in accordance with plant procedures and will verified during post-installation testing. The turbine first stage pressure values are details of system design that will be adequately controlled outside the TS. Removal of the turbine first stage pressure values from the TS is consistent with NUREG-1433, "Standard Technical Specifications, General Electric Plants, BWR/4."

Section	Proposed Change	Justification
Table 4.3.1.1-1, Reactor Protection System Instrumentation Surveillance Requirements, Note (d)	Change the APRM CHANNEL CALIBRATION RTP threshold value to 24%.	The proposed change maintains consistency with the changes to TS 2.1.1 and LCOs 3.2.1, 3.2.3 and 3.2.4. Refer to PUSAR Section 9.1.1.
Table 3.3.2-2 - Isolation Actuation Instrumentation Setpoints, Trip Function 3.d	Revise the Main Steam Line Flow – High Trip Setpoint to 162.8 psid and the AV to 169.3 psid	The analytical limit in percent of rated steam flow is unchanged. Refer to PUSAR Section 5.3.1.
LCO 3.3.4.2 - End-of-Cycle Recirculation Trip System Instrumentation, Applicability	Revise the End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation RTP thermal monitoring threshold value to 24%.	The proposed change is consistent with the changes to TS 2.1.1 and LCOs 3.2.1, 3.2.3 and 3.2.4. Refer to PUSAR Section 5.3.2 and Table 5-1
Table 3.3.4.2-1 - EOC-RPT Trip System Instrumentation, Note (b)	Revise the automatic bypass RTP value to 24%. Remove the values for turbine first stage pressure.	Refer to PUSAR Section 5.3.2 and Table 5-1 for change to RTP value. Modifications to the high pressure turbine will change the relationship of turbine first stage pressure to reactor power. The turbine first stage pressure setpoint will be controlled in accordance with plant procedures and will verified during post-installation testing. The turbine first stage pressure values are details of system design that will be adequately controlled outside the TS. Removal of the turbine first stage pressure values from the TS is consistent with NUREG-1433, "Standard Technical Specifications, General Electric Plants, BWR/4."
Table 3.3.6-2 - Control Rod Block Instrumentation Setpoints, Trip Function 2.a	Revise the APRM Flow Biased Neutron Flux – Upscale Trip Setpoint to $\leq 0.57\ (w - \Delta w) + 53\%$. Revise the allowable value to: $\leq 0.57\ (w - \Delta w) + 56\%$.	[Note: This proposed TS change assumes NRC approval of changes proposed in PSEG letter LR-N04-0062, "Request for License Amendment: ARTS/MELLLA Implementation," June 7, 2004] Refer to PUSAR Section 5.3.3 and Table 5-1.

Section	Proposed Change	Justification
Table 3.3.6-2 - Control Rod Block Instrumentation Setpoints, Trip Function 2.d	Revise the APRM Neutron Flux-Upscale, Startup (Rod Block) Setpoint to 11%. Revise the Allowable Value to 13%.	The proposed changes maintain the existing margin to the APRM Neutron Flux - Upscale, Setdown Trip Setpoint. Refer to PUSAR Section 5.3.7 and Table 5-1.
LCO 3.3.11 - Oscillation Power Range Monitor Instrumentation, Applicability; and LCO 3.3.11, Action c	Change 25% RTP to 24% RTP	The proposed change maintains consistency with the changes to TS 2.1.1 and TS 3.2.3.
SR 4.3.11.5	Change 30% RTP to 26.1% RTP	The proposed change maintains the same absolute power/flow region boundaries for the OPRM trip-enabled region.
LCO 3.4.1.1 - Recirculation Loops, Action a.1.b; and SR 4.4.1.1.1.a	Change the maximum power for single loop operation to 60.86%.	The proposed changes maintain the existing licensed region for single loop operation. Refer to PUSAR Section 3.6.
LCO 3.4.1.2 - Jet Pumps, SRs 4.4.1.2.a and 4.4.1.2.c	Change 25% RTP to 24% RTP.	The proposed changes are consistent with changes to the applicability of power distribution limits for ECCS performance analyses.
LCO 3.6.1.2.c - Primary Containment Leakage Table 3.6.3-1 - Primary Containment Isolation Valves, Note 3	Change Pa to 50.6 psig.	The proposed change reflects the updated containment pressure response. Refer to PUSAR Section 4.1.1.
LCOs 3.6.1.2.d and 3.6.1.2.e-Primary Containment Leakage SR 4.6.1.2.g Table 3.6.3-1 - Primary Containment Isolation Valves, Notes 2 and 4	Change 1.10 Pa to 55.7 psig.	The proposed changes reflect the updated containment pressure response. Refer to PUSAR Section 4.1.1.
LCO 3.7.7 - Main Turbine Bypass System, Applicability and Action	Change 25% RTP to 24% RTP.	The proposed change maintains consistency with the changes to TS 2.1.1 and LCOs 3.2.1, 3.2.3 and 3.2.4. Refer to PUSAR Section 9.1.1
LCO 3.10.2 - Rod Worth Minimizer	Change 10% RTP to 8.6% RTP.	Proposed change maintains consistency with proposed changes to LCO 3.1.4.1.

Section	Proposed Change	Justification
TS 6.8.4.f - Primary Containment Leakage Rate Testing Program	Change Pa to 50.6 psig.	The proposed changes reflects the updated containment pressure response. Refer to PUSAR Section 4.1.1.

Selected TS references to RTP that are not being changed are listed in Table 2 with the bases for not changing the current TS values.

Table 2
Unchanged TS References to % RTP

Section	Bases for No Change
Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.b.2	APRM Flow Biased Simulated Thermal Power High Flow Clamped Trip Setpoint and Allowable Value are not changed since the function is not credited in any transient analyses. Refer to PUSAR Section 5.3.3.
Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.c	APRM Fixed Neutron Flux - Upscale Trip Setpoint and Allowable Value are not changed because the Analytical Limit is not changed.
SR 4.1.3.2, maximum control rod scram insertion time	The 40% RTP used in the surveillance requirement is a value chosen for convenience, sufficiently higher than the Rod Worth Minimizer low power setpoint to minimize the need for out-of-sequence rod withdrawals while ensuring the SR is performed within a reasonable time after startup from a refueling outage or a shutdown lasting more than 120 days.
LCO 3.1.4.3 - Rod Block Monitor, Applicability	The Rod Block Monitor is not credited in the evaluation of the control rod withdrawal error.
Table 4.3.1.1-1, Reactor Protection System Instrumentation Surveillance Requirements, Note (d)	The 2% RTP value used for the CHANNEL CALIBRATION Surveillance Requirement is a tolerance value and does not need to be rescaled.
Table 3.3.2-1 - Isolation Actuation Instrumentation, Note ##	The Note restricts operation of the hydrogen water chemistry system to power levels greater than or equal to 20% of RTP. Leaving the value unchanged is conservative.
Table 3.3.2-2 - Isolation Actuation Instrumentation Setpoints, Note ###	The Note restricts operation of the hydrogen water chemistry system to power levels greater than or equal to 20% of RTP. Leaving the value unchanged is conservative.
Table 3.3.6-1 - Control Rod Block Instrumentation, Note *	The Rod Block Monitor is not credited in the evaluation of the control rod withdrawal error.
Table 3.3.6-2 - Control Rod Block Instrumentation Setpoints, Trip Function 1	The Rod Block Monitor is not credited in the evaluation of the control rod withdrawal error.

Section	Bases for No Change
Table 3.3.6-2 - Control Rod Block Instrumentation Setpoints, Trip Function 2.c	Leaving the APRM Control Rod Block Downscale Trip Setpoint and Allowable Value unchanged is conservative because it results in the trip function occurring at a higher absolute power.
LCO 3.4.1.1 - Recirculation Loops, Action 1.g and SR 4.4.1.1.2	As noted in Reference 4, thermal stratification during single loop operation is known not to be a concern at power levels above 38%. Leaving the value unchanged is conservative.
LCO 3.6.6.2 - Drywell and Suppression Chamber Oxygen Concentration, Applicability and SR 4.6.6.2	15% RTP establishes the 24 hour windows for inerting and de-inerting the containment during plant startups and shutdowns. The sequence of operations during plant startups and shutdowns is substantially unchanged by the EPU. Therefore, the current TS value does not need to be changed.
LCO 3.10.4 - Recirculation Loops; and SR 4.10.4.2	The 5% RTP value is high enough to allow PHYSICS TESTS to be performed yet still below RWM / APRM upscale – setdown, etc., and well below ECCS design basis concerns relative to flow mismatch.

3. BACKGROUND

Hope Creek was originally licensed to operate at a maximum power level of 3293 MWt. In 2001, the authorized maximum power level was increased to 3339 MWt (Amendment No. 131, TAC No. MB0644).

An increase in the electrical output of a BWR plant is accomplished primarily by generating and supplying higher steam flow to the turbine-generator. As currently licensed, most BWR plants, including Hope Creek, have an as-designed equipment and system capability to accommodate steam flow rates above the original rating. In addition, continuing improvements in the analytical techniques (computer codes and data) based on several decades of BWR safety technology, plant performance feedback, and improved fuel and core designs have resulted in a significant increase in the design and operating margins between calculated safety analysis results and the licensing limits. These available safety analyses differences, combined with the excess as-designed equipment, system and component capabilities, provide BWR plants the capability to achieve an increase in their thermal power ratings of between 5 and 20% without major nuclear steam supply system (NSSS) hardware modifications.

In March 2003, the NRC approved the use of the CLTR as a basis for power uprate license amendment requests, subject to limitations specified in the CLTR and in the associated NRC safety evaluation. The limitations relate to license amendment requests that may not be pursued concurrently with the power uprate request. In addition, licensees proposing to utilize fuel designs other than GE fuel, up through GE 14 fuel, may reference the CPPU LTR as a basis for their power uprate for areas

other than those involving reactor systems and for fuel issues which are not impacted by the fuel design. The NRC's approvals of ELTR1 (Reference 2) and ELTR2 (Reference 3) do not include similar specific limitations on fuel type. In Reference 5, the NRC described plant-specific information that licensees must submit, in addition to the information routinely submitted, for an extended power uprate application with a mixed core.

A higher steam flow is achieved by increasing the reactor power along specified control rod and core flow lines. A limited number of operating parameters are changed, some setpoints are adjusted and instruments are recalibrated. Plant procedures are revised, and tests similar to some of the original startup tests are performed. Modifications to some non-safety power generation equipment will be implemented over time, as needed.

Detailed evaluations of the reactor, engineered safety features, power conversion, emergency power, support systems, environmental issues, and design basis accidents were performed. These evaluations demonstrate that Hope Creek can safely operate at 3840 MWt.

4. TECHNICAL ANALYSIS

The safety analysis report in Attachment 4 summarizes the results of the significant safety evaluations performed that justify uprating the licensed thermal power at Hope Creek.

Modification Summary
The generation and supply of higher steam flow for the turbine generator accomplishes an increase in electrical output of a BWR plant. Most BWR plants, including Hope Creek, as currently licensed, have an as-designed equipment and system capability to accommodate steam flow rates at least 5% above the original rating. In addition, continuing improvements in the analytical techniques (computer codes and data) based on several decades of BWR safety technology, plant performance feedback, and improved fuel and core designs have resulted in a significant increase in the design and operating margins between calculated safety analysis results and the licensing limits. These available safety analyses differences, combined with the excess as-designed equipment, system and component capabilities, provide BWR plants the capability to achieve an increase in their thermal power ratings of between 5 and 20% without major nuclear steam supply system (NSSS) hardware modifications, and to provide for power increases to 20% with limited non-safety hardware modifications, with no significant increase in the hazards presented by the plant as approved by the NRC at the original license stage.

The plan for achieving higher power is to extend the power to flow map along the standard Maximum Extended Load Line Limit Analysis (MELLLA) power to flow upper boundary. The extension of the power to flow map does not require an

increase in the maximum core flow limit or operating pressure over the pre-CPPU values.

Discussions of Issues Being Evaluated
Hope Creek performance and responses to hypothetical accidents and transients have been evaluated for a CPPU license amendment. This safety assessment summarizes the safety significant plant reactions to events analyzed for the licensing of Hope Creek, and the potential effects on various margins of safety, and thereby concludes that no significant hazards consideration will be involved.

CPPU Analysis Basis
Hope Creek is currently licensed for operation up to 3339 MWt, and most of the current safety analyses are based on this value. The Cycle 13 ECCS-LOCA analyses are based on 1.02 times CLTP. However, the containment safety analyses are based on a power level of 1.02 times the original licensed power level. The CPPU RTP level included in this evaluation is 115% of the current licensed thermal power level. The CPPU safety analyses are based on a power level of at least 1.02 times the CPPU power level unless the Regulatory Guide 1.49 two percent power factor is already accounted for in the analysis methods.

Cycle-Specific Confirmations
Some evaluation items in the PUSAR dispositioned based on experience or on equilibrium cycle evaluations will be confirmed during cycle-specific evaluations for the EPU implementation cycle and subsequent cycles because they are sensitive to the specific core design.

PSEG's reload design and licensing process, including reload design meetings with the fuel vendor, will be used to ensure cycle specific evaluations address PUSAR dispositions that are sensitive to the specific core design. The process is controlled by administrative procedures that provide the sequence of events and requirements for implementing a cycle specific reload core design. NC.NF-AP.ZZ-6002(Q) defines responsibilities and requirements for establishing the reload design schedule and specification, for addressing licensing, configuration management and industry operating experience, for analysis activities that support the reload design and licensing effort, for addressing the impact on the reload core design and licensing basis of concurrent plant design and licensing changes, for interfacing with and reviewing the nuclear fuel vendor activities and information, for providing training to operations, reactor engineering and senior management, and for maintaining documentation. NC.NF-AP.ZZ-6002 requires input from functional groups that may be impacted by the reload core design, such as chemistry, operations, and reactor engineering. NC.NF-AP.ZZ-6002(Q) also requires senior management approval for significant changes in reload core design or operating strategy.

The NRC most recently evaluated PSEG's reload core design and licensing process in 1998 and concluded that PSEG maintained acceptable control over reload core design (Reference 6). The reload design and licensing process in place today is

fundamentally the same as the process that was evaluated in 1998, except for the incorporation of enhancements or best practices such as those associated with INPO SOER 03-02, "Managing Core Design Changes."

HCGS Nuclear Fuel Section personnel participate in several forms of communications with the fuel vendor that can be considered reload design meetings. Nuclear Fuel Section supervision and core design and safety analyses staff have direct input and review / concurrence / approval responsibilities when participating in these meetings. Once a reload design and licensing campaign is initiated, frequent (typically weekly) phone calls are held to discuss requirements, issues and schedule. During the reload campaign, design review meetings are held in addition to the weekly phone calls for key activities, such as the eigenvalue review at the initiation of the core design or the transient selection review prior to reload safety analysis work initiating. Prior to the fuel vendor issuing the Supplemental Reload Licensing Report (SRLR), a final reload design and licensing review meeting is held that addresses all aspects of the activities that will result in the fuel vendor issuing the SRLR for HCGS acceptance. These meetings are documented in various ways, e.g., weekly meeting agenda/minutes up to and including formal design review packages that are prepared by the fuel vendor in collaboration with HCGS Nuclear Fuel Section staff.

Fuel Thermal Limits
No new fuel design is required for CPPU. No increase in allowable peak bundle power is requested for CPPU. The current fuel design limits will continue to be met at the CPPU RTP. Analyses for each fuel reload will continue to meet the criteria accepted by the NRC as specified in NEDO-24011, "GESTAR II" or otherwise approved in the Technical Specifications. Future fuel designs will meet acceptance criteria approved by the NRC.

Makeup Water Sources
The BWR design concept includes a variety of ways to pump water into the reactor vessel to mitigate all types of events. There are numerous safety-related and non-safety-related cooling water sources. The safety-related cooling water sources alone would maintain core integrity by providing adequate cooling water.

CPPU does not result in an increase or decrease in the available water sources, nor does it change the selection of those assumed to function in the safety analyses. NRC-approved methods were used for analyzing the performance of the Emergency Core Cooling Systems (ECCS) during loss-of-coolant-accidents.

CPPU results in an increase in decay heat, and thus, the time required to cooldown to cold shutdown conditions increases. This is not a safety concern, and the existing cooling capacity can bring the Hope Creek unit to cold shutdown within a time span that continues to meet current licensing requirements.

Design Basis Accidents

Design Basis Accidents (DBAs) are very low probability hypothetical events whose characteristics and consequences are used in the design of the plant, so that the plant can mitigate their consequences to within acceptable regulatory limits. For BWR licensing evaluations, capability is demonstrated for coping with the range of hypothetical pipe break sizes in the largest recirculation, steam, and feedwater lines, a postulated break in one of the ECCS lines, and the most limiting small lines. This break range bounds the full spectrum of large and small, high and low energy line breaks; and ensures the success of plant systems to mitigate the accidents, while accommodating a single active equipment failure in addition to the postulated LOCA. Several of the most significant licensing assessments are made using these LOCA ground rules. These assessments are:

1. **Challenges to Fuel**

   Emergency Core Cooling Systems (ECCS) are described in Section 6.3 of the Hope Creek Updated Final Safety Analysis Report (UFSAR). The ECCS Performance Evaluation described in Attachment 4, Section 4.3 demonstrates the continued conformance to the acceptance criteria of 10 CFR 50.46. As mentioned above, a complete spectrum of pipe breaks is investigated from the largest recirculation line down to the most limiting small line break. As shown in Attachment 4, Table 4-2, the licensing safety margin is not affected by CPPU. The increased peak centerline temperature (PCT) consequences for CPPU are insignificant compared to the large amount by which the results are below the regulatory criteria. Therefore, the ECCS safety margin is not affected by CPPU.

2. **Challenges to the Containment**

   Attachment 4, Table 4-1 provides the results of analyses of the Hope Creek containment response to the most severe LOCAs. The effect of CPPU on the peak values for containment pressure and temperature confirms the suitability of the plant for operation at CPPU RTP. Also, the effects of CPPU on the conditions that affect the containment dynamic loads are determined, and the plant is judged satisfactory for CPPU operation. Where plant conditions with CPPU are within the range of conditions used to define the current dynamic loads, current safety criteria are met and no further structural analysis is required. The change in short-term containment response is negligible. Because there will be more residual heat with CPPU, the containment long-term response slightly increases. However, containment pressures and temperatures remain below their design limits following any design basis accident, and thus, the containment and its cooling systems are judged to be satisfactory for CPPU operation. The small increase in the calculated post LOCA suppression pool temperature above the currently assumed peak temperature was evaluated and determined to be acceptable.

3. **Design Basis Accident Radiological Consequences**
The Hope Creek UFSAR provides the radiological consequences for each DBA. The magnitude of the potential consequences is dependent upon the quantity of fission products released to the environment, the atmospheric dispersion factors and the dose exposure pathways. The atmospheric dispersion factors and the dose exposure pathways do not change. Therefore, the only factor, which could influence the magnitude of the consequences, is the quantity of activity released to the environment. This quantity is a product of the activity released from the core and the transport mechanisms between the core and the effluent release point.

License Amendment No. 134 (Reference 7) approved changes to the TS based on full implementation of an alternative source term (AST) pursuant to 10CFR50.67 using the guidance provided in Regulatory Guide (RG) 1.183.

For CPPU, the Control Rod Drop Accident (CRDA), Loss-of-Coolant Accident (LOCA), Fuel Handling Accident (FHA), Main Steamline Break Accident (MSLBA) and instrument line break accident (ILBA) are reanalyzed.

For an ILBA, the transport mechanism potentially influenced by an increase in reactor power is the quantity of coolant mass discharged to the environment. For the ILBA, increased mass loss will occur if the operating pressure is increased. However, the requested CPPU does not need or include an increase in operating pressure, and thus, the consequences of an ILBA do not change. The ILBA is not a limiting event.

For the MSLBA and ILBA, the primary coolant activity used in the evaluation of these postulated events is unaffected by CPPU. The primary coolant activity is based on Technical Specification limits, which remain unchanged for CPPU.

For the remaining DBAs, the only parameter of importance is the activity released from the fuel. Because the mechanism of fuel failure is not influenced by CPPU, the only parameter of importance is the actual inventory of fission products in the fuel rod. If the only parameter affecting fuel is an increase in thermal power, then the increase in the quantity of fission products can be assumed to be proportional to the increase in power.

The DBA that has historically been limiting from a radiological viewpoint is the LOCA, for which USNRC Regulatory Guide 1.183, Appendix A guidance has been applied. Adherence to the guidance in RG 1.183, and the use of the specific values/limits contained in the Technical Specifications with as-tested post-accident performance of the safety grade engineered safety functions (ESF), provide the assurance for sufficient safety margin, including a margin to account for analysis uncertainties. It is, therefore, concluded that the existing LOCA radiological consequences, as a result of CPPU, are increased

proportional to the increase in power, and, as shown in Section 9.2 of the PUSAR, these consequences remain below regulatory guidelines. The CPPU LOCA evaluation results include the 2% power uncertainty factor from Regulatory Guide 1.49.

The results of all radiological analyses remain below the allowable limits of 10 CFR 50.67 and Table 6 in Regulatory Guide 1.183. Therefore, all radiological safety margins are maintained.

Anticipated Operational Occurrence Analyses
The effects of Anticipated Operational Occurrences (AOO) are evaluated by investigating a number of disturbances of process variables and malfunctions or failures of equipment according to a scheme of postulating initiating events. These events are primarily evaluated against the Safety Limit Minimum Critical Power Ratio (SLMCPR) and other applicable Specified Acceptable Fuel Design Limits (SAFDLs) such as the avoidance of fuel centerline melting and not exceeding 1% fuel cladding plastic strain. Compliance with SLMCPR and with the other applicable SAFDLs has been determined using NRC-approved methods. As described in Section 9.1 of Attachment 4, the limiting AOOs have been evaluated for the CPPU RTP conditions. No change to the basic characteristic of any of the limiting events is caused by the CPPU. The results of the CPPU AOO evaluations demonstrate that CPPU RTP operation can be safely implemented consistent with the bases for the Technical Specification Power Distribution Limits. Licensing acceptance criteria are not exceeded. Continued compliance with the SLMCPR and other applicable Specified Acceptable Fuel Design Limits will be confirmed on a cycle specific basis. Therefore, the margin of safety is not affected by CPPU.

Combined Effects
DBAs are postulated using deterministic regulatory criteria to evaluate challenges to the fuel, containment, and off-site radiation dose limits. The off-site dose evaluation performed in accordance with Regulatory Guide 1.183 calculates more severe radiological consequences than the combined effects of bounding DBAs that produce the greatest challenge to the fuel and containment. In contrast, the DBA that produces the highest PCT does not result in damage to the fuel equivalent to the assumptions used in the off-site dose evaluation, and the DBA that produces the maximum containment pressure, does not result in leak rates to the atmosphere equivalent to the assumptions used in the off-site dose evaluation. Thus, the off-site doses calculated in conformance with Regulatory Guide 1.183 are conservative compared to the combined effect of the bounding DBA evaluations.

Equipment Qualification
Hope Creek safety related electrical and mechanical equipment was evaluated against the criteria appropriate for operation at EPU. Changes in environmental conditions due to EPU will not adversely affect existing equipment qualifications.

Balance-of-Plant
Balance-of-plant (BOP) systems and equipment used to perform safety-related and normal operation functions have been reviewed for CPPU in a manner comparable to that for safety-related NSSS systems/equipment. CPPU operation for BOP systems and equipment is justified by generic or Hope Creek specific evaluations, which include the limited modifications that were made to BOP components.

Core Thermal Power Measurement
The current licensed thermal power level (3339 MWt) is based on reduced uncertainty in core thermal power measurement achieved with the Crossflow ultrasonic flow measurement system as described in Reference 8. If the Crossflow system becomes unavailable, plant operation at 3339 MWt may continue for 24 hours after the last valid correction factor was obtained from the Crossflow system. Procedural guidance directs that reactor power be reduced to a level less than or equal to the previously licensed power level (3293 MWt) if the Crossflow system cannot be restored to operation within 24 hours. Core power is then maintained at a level less than or equal to 3293 MWt until the Crossflow system is returned to service and a heat balance in accordance with SR 4.3.1.1 is performed with updated correction factors from the Crossflow system.

Analyses for the proposed CPPU are based on a power level at least 1.02 times the CPPU power level unless the Regulatory Guide 1.49 two percent power factor is already accounted for in the analysis methods. Therefore, following NRC approval of the proposed amendment, plant procedures will no longer direct that power be reduced if the Crossflow system becomes unavailable.

Probabilistic Risk Assessment

Attachment 4, Section 10.5 describes the results of Level 1 and Level 2 Probabilistic Risk Assessments (PRAs) performed for the CPPU. When compared to the risk-acceptance guidelines presented in Regulatory Guide 1.174, the calculated changes in core damage frequency (CDF) and large early release frequency (LERF) are very small. The CLTP and CPPU CDFs are both well below 1E-4 events per year for the internal events. The change in CDF associated with CPPU implementation is 6.8E-7/yr. The CLTP and CPPU LERFs are both well below 1E-5 events per year for the internal events. The change in LERF associated with CPPU implementation is 6.1E-8/yr.

Primary Containment Leakage Rate Testing Program
Surveillance Requirement 4.6.1.2.a requires that primary containment leakage rates be demonstrated in accordance with the Primary Containment Leakage Rate Testing Program. The testing program is required by 10 CFR 50.54(o) and 10 CFR 50 Appendix J and is described in Technical Specification 6.8.4.f. Test intervals are established on a performance basis in accordance with 10 CFR 50 Appendix J, Option B.

The Type A integrated leak rate test and the Type B and C local leak rate tests are performed at the calculated peak containment pressure (Pa). Pa increases to 50.6 psig for the EPU; and Technical Specification 6.8.4.f is being revised to reflect the change. However, with substantial margin to the leakage rate acceptance limits based upon current leak rate test results, it is not necessary to reperform all of the leak rate tests at the higher Pa before implementation of the EPU.

Proposed License Condition 2.C.(16) would allow leak rate tests required by Surveillance Requirement 4.6.1.2.a to be considered to be performed per SR 4.0.1, upon implementation of the license amendment approving the proposed EPU, until the next scheduled performance. This would preclude having to perform the affected leak rate tests before their next scheduled performance solely for the purpose of documenting compliance. The allowance provided in License Condition 2.C.(16) would not supercede that aspect of SR 4.0.1 that governs cases where it is believed that, if the SR were performed, it would not be met. Performance of the leak rate tests merely to document compliance would unnecessarily divert resources, interfere with plant operations, potentially incur additional personnel dose, and would not improve plant safety.

5. REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

PSEG Nuclear LLC (PSEG) has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment" as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The probability (frequency of occurrence) of Design Basis Accidents occurring is not affected by the increased power level, because Hope Creek continues to comply with the regulatory and design basis criteria established for plant equipment. A probabilistic risk assessment demonstrates that the calculated core damage frequencies do not significantly change due to constant pressure power uprate (CPPU). Scram setpoints (equipment settings that initiate automatic plant shutdowns) are established such that there is no significant increase in scram frequency due to CPPU. No new challenges to safety-related equipment result from CPPU.

   The changes in consequences of hypothetical accidents, which would occur from 102% of the CPPU (rated thermal power) RTP compared to

those previously evaluated, are in all cases insignificant. The CPPU accident evaluations do not exceed any of the NRC-approved acceptance limits. The spectrum of hypothetical accidents and transients has been investigated, and are shown to meet the plant's currently licensed regulatory criteria. In the area of fuel and core design, for example, the Safety Limit Minimum Critical Power Ratio (SLMCPR) and other applicable Specified Acceptable Fuel Design Limits (SAFDLS) are still met. Continued compliance with the SLMCPR and other SAFDLs will be confirmed on a cycle specific basis consistent with the criteria accepted by the NRC as specified in NEDO-24011, "General Electric Standard Application for Reactor Fuel, GESTAR II."

Challenges to the Reactor Coolant Pressure Boundary were evaluated at CPPU conditions (pressure, temperature, flow, and radiation) and were found to meet their acceptance criteria for allowable stresses and overpressure margin.

Challenges to the containment have been evaluated, and the containment and its associated cooling systems continue to meet 10 CFR 50 Appendix A Criterion 38, Long Term Cooling, and Criterion 50, Containment. The small increase in the calculated post LOCA suppression pool temperature above the currently assumed peak temperature was evaluated and determined to be acceptable.

Radiological release events (accidents) have been evaluated, and shown to meet the guidelines of 10 CFR 50.67.

Therefore, the proposed change does not involve a significant increase in the probability or radiological consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   Equipment that could be affected by CPPU has been evaluated. No new operating mode, safety-related equipment lineup, accident scenario or equipment failure mode was identified. The full spectrum of accident considerations has been evaluated, and no new or different kind of accident has been identified. CPPU uses developed technology, and applies it within the capabilities of existing plant equipment in accordance with presently existing regulatory criteria to include NRC approved codes, standards and methods. No new power dependent accidents have been identified.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No.

The CPPU affects only design and operational margins. Challenges to the fuel, reactor coolant pressure boundary, and containment were evaluated for CPPU conditions. Fuel integrity is maintained by meeting existing design and regulatory limits. The calculated loads on all affected structures, systems and components, including the reactor coolant pressure boundary, will remain within their design allowables for all design basis event categories. No NRC acceptance criterion is exceeded. The margins of safety currently designed into the plant are not affected by CPPU. Because the Hope Creek configuration and responses to transients and hypothetical accidents do not result in exceeding the presently approved NRC acceptance limits, CPPU does not involve a significant reduction in a margin of safety.

Based on the above, PSEG concludes that the proposed changes present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements/Criteria

10 CFR 50.36 (c)(2)(ii) Criterion 2, requires that TS LCOs include process variables, design features, and operating restrictions that are initial conditions of design basis accident analysis. The Technical Specifications ensure that the Hope Creek system performance parameters are maintained within the values assumed in the safety analyses. The Technical Specification changes justified by the safety analyses are made in accordance with methodology approved for Hope Creek and continue to provide a comparable level of protection as Hope Creek Technical Specifications previously issued by the NRC. Applicable regulatory requirements and significant safety evaluations performed in support of the proposed changes are described in Attachment 4.

In conclusion, based on the considerations discussed above, (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 amendment will not be inimical to the common defense and security or to the health and safety of the public.

6. ENVIRONMENTAL CONSIDERATION

The proposed TS changes required for implementation of EPU meet the requirements for an environmental review as set forth in 10 CFR 51.20, "Criteria For And Identification Of Licensing And Regulatory Actions Requiring Environmental Impact Statements." A supplement to the Hope Creek Environmental Report in Attachment 3 concludes that worker radiation exposures will continue to be significantly less than the limits established by federal regulation. The evaluation described in Attachment 3 supports increases in the licensed power level up to 3952 MWt, which bounds the proposed increase to 3840 MWt.

7. REFERENCES

1. GE Nuclear Energy, "Constant Pressure Power Uprate," Licensing Topical Report NEDC-330004P-A, Revision 4, July 2003

2. GE Nuclear Energy, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," Licensing Topical Report NEDC-32424P-A, February 1999

3. GE Nuclear Energy, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," Licensing Topical Reports NEDC-32523P-A, February 2000; NEDC-32523P-A, Supplement 1 Volume I, February 1999; and Supplement 1 Volume II, April 1999

4. HC License Amendment No. 63, Single Loop Operation Instrumentation (TAC No. M85771)

5. NRC letter dated June 25, 2003, "Review of Extended Power Uprates for Boiling Water Reactors"

6. NRC Inspection Report 50-354/98-09, October 2, 1998

7. HC License Amendment No. 134

8. HC License Amendment No. 131

HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
REVISIONS TO THE TECHNICAL SPECIFICATIONS

FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION PAGES WITH PROPOSED CHANGES

The following sections of Facility Operating License No. NPF-57 are affected by this change request:

FOL Paragraph	Page
2.C.(1)	3
2.C.(11)	5
2.C.(16)	7

The following Technical Specifications for Facility Operating License No. NPF-57 are affected by this change request:

Technical Specification	Page
1.35	1-6
2.1.1	2-1
Table 2.2.1-1	2-4
3/4.1.4	3/4 1-16
3/4.2.1	3/4 2-1
3/4.2.3	3/4 2-3
3/4.2.4	3/4 2-5
Table 3.3.1-1	3/4 3-5
Table 4.3.1.1-1	3/4 3-8
Table 3.3.2-2	3/4 3-22

Technical Specification	Page
3/4.3.4	3/4 3-45
Table 3.3.4.2-1	3/4 3-47
Table 3.3.6-2	3/4 3-59
3/4.3.11	3/4 3-110
3/4.4.1	3/4 4-1 3/4 4-2a 3/4 4-4
3/4.6.1	3/4 6-2 3/4 6-4
Table 3.6.3-1	3/4 6-42
3/4.7.7	3/4 7-21
3/4.10.2	3/4 10-2
6.8.4.f	6-16b

Insert 1

(16) Leak rate tests required by Surveillance Requirement 4.6.1.2.a to be performed in accordance with the Primary Containment Leakage Rate Testing Program are not required to be performed until their next scheduled performance, which is due at the end of the first test interval that begins on the date the test was last performed prior to implementation of Amendment No. [XXX].

(4) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use at any time any byproduct, source and 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;

(5) PSEG Nuclear LLC, 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

(6) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I 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 or incorporated below:

3840

(1) Maximum Power Level

PSEG Nuclear LLC is authorized to operate ~~the~~ facility at reactor core power levels not in excess of 3339 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No.   , and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into the license. PSEG Nuclear LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Inservice Testing of Pumps and Valves (Section 3.9.6, SSER No. 4)*

This License Condition was satisfied as documented in the letter from W. R. Butler (NRC) to C. A. McNeill, Jr. (PSE&G) dated December 7, 1987. Accordingly, this condition has been deleted.

*The parenthetical notation following the title of many license conditions denotes the section of the Safety Evaluation Report and/or its supplements wherein the license condition is discussed.

(8) Solid Waste Process Control Program (Section 11.4.2, SER; Section 11.4, SSER No. 4)

PSEG Nuclear shall obtain NRC approval of the Class B and C solid waste process control program prior to processing Class B and C solid wastes.

(9) Emergency Planning (Section 13.3, SSER No. 5)

In the event that the NRC finds that the lack of progress in completion of the procedures in the Federal Emergency Management Agency's final rule, 44 CFR Part 350, is an indication that a major substantive problem exists in achieving or maintaining an adequate state of emergency preparedness, the provisions of 10 CFR Section 50.54(s)(2) will apply.

(10) Initial Startup Test Program (Section 14, SSER No. 5)

Any changes to the Initial Startup Test Program described in Section 14 of the FSAR made in accordance with the provisions of 10 CFR 50.59 shall be reported in accordance with 50.59(b) within one month of such change.

(11) Partial Feedwater Heating (Section 15.1, SER; Section 15.1, SSER No. 5; Section 15.1, SSER No. 6)

The facility shall not be operated with reduced feedwater temperature for the purpose of extending the normal fuel cycle. ~~After the first operating cycle, the facility shall not be operated with a feedwater heating capacity that would result in a rated power feedwater temperature less than 400°F~~ unless analyses supporting such operation are submitted by the licensee and approved by the staff.

(12) Detailed Control Room Design Review (Section 18.1, SSER No. 5)

a. PSE&G shall submit for staff review Detailed Control Room Design Review Summary Reports II and III on a schedule consistent with, and with contents as specified in, its letter of January 9, 1986.

b. Prior to exceeding five percent power, PSE&G shall provide temporary zone markings on safety-related instruments in the control room.

4) The trust agreement shall not be modified in any material respect without prior written notification to the Director, Office of Nuclear Reactor Regulation.

5) The trustee, investment advisor, or anyone else directing the investments made in the trust shall adhere to a "prudent investor" standard, as specified in 18 CFR 35.32(3) of the Federal Energy Regulatory Commission's regulations.

c. PSEG Nuclear LLC shall not take any action that would cause PSEG Power LLC or its parent companies to void, cancel, or diminish the commitment to fund an extended plant shutdown as represented in the application for approval of the transfer of this license from PSE&G to PSEG Nuclear LLC.

INSERT 1

D. The facility requires exemptions from certain requirements of 10 CFR Part 50 and 10 CFR Part 70. An exemption from the criticality alarm requirements of 10 CFR 70.24 was granted in Special Nuclear Material License No. 1953, dated August 21, 1985. This exemption is described in Section 9.1 of Supplement No. 5 to the SER. This previously granted exemption is continued in this operating license. An exemption from certain requirements of Appendix A to 10 CFR Part 50, is described in Supplement No. 5 to the SER. This exemption is a schedular exemption to the requirements of General Design Criterion 64, permitting delaying functionality of the Turbine Building Circulating Water System-Radiation Monitoring System until 5 percent power for local indication, and until 120 days after fuel load for control room indication (Appendix R of SSER 5). Exemptions from certain requirements of Appendix J to 10 CFR Part 50, are described in Supplement No. 5 to the SER. These include an exemption from the requirement of Appendix J, exempting main steam isolation valve leak-rate testing at 1.10 Pa (Section 6.2.6 of SSER 5); an exemption from Appendix J, exempting Type C testing on traversing incore probe system shear valves (Section 6.2.6 of SSER 5); an exemption from Appendix J, exempting Type C testing for instrument lines and lines containing excess flow check valves (Section 6.2.6 of SSER 5); and an exemption from Appendix J, exempting Type C testing of thermal relief valves (Section 6.2.6 of SSER 5). These exemptions are authorized by law, will not present an undue risk to the public health and safety, and are consistent with the common defense and security. These exemptions are hereby granted. The special circumstances regarding each exemption are identified in the referenced section of the safety evaluation report and the supplements thereto. These exemptions are granted pursuant to 10 CFR 50.12. With these exemptions, the facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission.

PROCESS CONTROL PROGRAM

1.33 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, test, and determinations to be made to ensure that processing and packing of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

PURGE - PURGING

1.34 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.35 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3339 MWT. 3840

REACTOR PROTECTION SYSTEM RESPONSE TIME

1.36 REACTOR PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

REPORTABLE EVENT

1.37 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

ROD DENSITY

1.38 ROD DENSITY shall be the number of control rod notches inserted as a fraction of the total number of control rod notches. All rods fully inserted is equivalent to 100% ROD DENSITY.

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

THERMAL POWER, Low Pressure or Low Flow

2.1.1 THERMAL POWER shall not exceed ~~25%~~ 24% of RATED THERMAL POWER with the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With THERMAL POWER exceeding ~~25%~~ 24% of RATED THERMAL POWER and the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

THERMAL POWER, High Pressure and High Flow

2.1.2 With reactor steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow:

The MINIMUM CRITICAL POWER RATIO (MCPR) shall be ≥ 1.06 for two recirculation loop operation and shall be ≥ 1.08 for single recirculation loop operation.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With reactor steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow and the MCPR below the values for the fuel stated in LCO 2.1.2, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

REACTOR COOLANT SYSTEM PRESSURE

2.1.3 The reactor coolant system pressure, as measured in the reactor vessel steam dome, shall not exceed 1325 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3 and 4.

ACTION:

With the reactor coolant system pressure, as measured in the reactor vessel steam dome, above 1325 psig, be in at least HOT SHUTDOWN with reactor coolant system pressure less than or equal to 1325 psig within 2 hours and comply with the requirements of Specification 6.7.1.

TABLE 2.2.1-1

REAC[illegible]R PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	≤ 120/125 divisions of full scale	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-Upscale, Setdown	≤ ~~15%~~ 14% of RATED THERMAL POWER	≤ ~~20%~~ 19% of RATED THERMAL POWER
b. Flow Biased Simulated Thermal Power-Upscale		
1) Flow Biased	$\le 0.57(w-\Delta w)+58\%$** ~~≤ 0.66(w-Δw)+51%**~~ with a maximum of	$\le 0.57(w-\Delta w)+61\%$** ~~≤ 0.66(w-Δw)+54%**~~ with a maximum of
2) High Flow Clamped	≤ 113.5% of RATED THERMAL POWER	≤ 115.5% of RATED THERMAL POWER
c. Fixed Neutron Flux-Upscale	≤ 118% of RATED THERMAL POWER	≤ 120% of RATED THERMAL POWER
d. Inoperative	NA	NA
3. Reactor Vessel Steam Dome Pressure - High	≤ 1037 psig	≤ 1057 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 12.5 inches above instrument zero*	≥ 11.0 inches above instrument zero
5. Main Steam Line Isolation Valve - Closure	≤ 8% closed	≤ 12% closed

*See Bases Figure B 3/4 3-1.

**The Average Power Range Monitor Scram function varies as a function of recirculation loop drive flow (w). Δw is defined as the difference in indicated drive flow (in percent of drive flow which produces rated core flow) between two loop a[illegible] single loop operation at the same core f[illegible]. Δw = 0 for two recirculation loop operation. Δw = 9% fo[illegible]ngle recirculation loop operation.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

ROD WORTH MINIMIZER

LIMITING CONDITION FOR OPERATION

3.1.4.1 The Rod worth minimizer (RWM) shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2*#, when THERMAL POWER is less than or equal to ~~10%~~ 8.6% of RATED THERMAL POWER, minimum allowable low power setpoint.

ACTION:

a. With the RWM inoperable after the first 12 control rods are fully withdrawn, operation may continue provided that control rod movement and compliance with the prescribed control rod pattern are verified by a second licensed operator or other technically qualified member of the unit technical staff who is present at the reactor control console.

b. With the RWM inoperable before the first twelve (12) control rods are fully withdrawn, one startup per calendar year may be performed provided that the control rod movement and compliance with the prescribed control rod pattern are verified by a second licensed operator or other technically qualified member of the unit technical staff who is present at the reactor control console.

c. Otherwise, control rod movement may be only by actuating the manual scram or placing the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.1.4.1 The RWM shall be demonstrated OPERABLE:

a. In OPERATIONAL CONDITION 2 within 8 hours prior to withdrawal of control rods for the purpose of making the reactor critical, and in OPERATIONAL CONDITION 1 within 8 hours prior to RWM automatic initiation when reducing THERMAL POWER, by verifying proper indication of the selection error of at least one out-of-sequence control rod.

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* Entry into OPERATIONAL CONDITION 2 and withdrawal of selected control rods is permitted for the purpose of determining the OPERABILITY of the RWM prior to withdrawal of control rods for the purpose of bringing the reactor to criticality.

\# See Special Test Exception 3.10.2.

3/4.2 POWER DISTRIBUTION LIMITS

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.1 All AVERAGE PLANAR LINEAR HEAT GENERATION RATES (APLHGRs) shall be less than or equal to the limits specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER.

ACTION:

With an APLHGR exceeding the limits specified in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore APLHGR to within the required limits within 2 hours or reduce THERMAL POWER to less than ~~25%~~ 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.1 All APLHGRs shall be verified to be equal to or less than the limits specified in the CORE OPERATING LIMITS REPORT:

a. Once within 12 hours after THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER and at least once per 24 hours thereafter.

b. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for APLHGR.

POWER DISTRIBUTION LIMITS

3/4.2.3 MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

3.2.3 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be equal to or greater than the MCPR limit specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER.

ACTION:

a. With the end-of-cycle recirculation pump trip system inoperable per Specification 3.3.4.2, operation may continue and the provisions of Specification 3.0.4 are not applicable provided that, within 1 hour, MCPR is determined to be greater than or equal to the EOC-RPT inoperable limit specified in the CORE OPERATING LIMITS REPORT.

b. With MCPR less than the applicable MCPR limit specified in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore MCPR to within ~~the~~ required limit within 2 hours or reduce THERMAL POWER to less than ~~25%~~ 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, shall be determined to be equal to or greater than the applicable MCPR limit specified in the CORE OPERATING LIMITS REPORT:

a. Once within 12 hours after THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER and at least once per 24 hours thereafter.

b. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

3/4.2.4 LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.4 The LINEAR HEAT GENERATION RATE (LHGR) shall not exceed the limit specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER.

ACTION:

With the LHGR of any fuel rod exceeding the limit specified in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore the LHGR to within the limit within 2 hours or reduce THERMAL POWER to less than ~~25%~~ 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.4 LHGR's shall be determined to be equal to or less than the limit specified in the CORE OPERATING LIMITS REPORT:

a. Once within 12 hours after THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER and at least once per 24 hours thereafter.

b. Initially and at least once per 12 hours when the reactor is operating on a LIMITING CONTROL ROD PATTERN for LHGR.

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

TABLE NOTATIONS

(a) A 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.

(b) This function shall be automatically bypassed when the reactor mode switch is in the Run position.

(c) Unless adequate shutdown margin has been demonstrated per Specification 3.1.1, the "shorting links" shall be removed from the RPS circuitry prior to and during the time any control rod is withdrawn*.

(d) The non-coincident NMS reactor trip function logic is such that all channels go to both trip systems. Therefore, when the "shorting links" are removed, the Minimum OPERABLE Channels Per the Trip System are 4 APRMS, 6 IRMS and 2 SRMS.

(e) An APRM channel is inoperable if there are less than 2 LPRM inputs per level or less than 14 LPRM inputs to an APRM channel.

(f) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(g) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

(h) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(i) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

delete

(j) This function ~~shall be~~ automatically bypassed when turbine first stage pressure is ~~≤ 158.7 psig~~ equivalent to THERMAL POWER less than ~~30%~~ 24% of RATED THERMAL POWER. ~~To allow for instrument accuracy, calibration, and drift, a setpoint of ≤ 135.7 psig is used.~~

delete

(k) Also actuates the EOC-RPT system.

*Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

TABLE 4.3.1.1-1 (Continued)
REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
8. Scram Discharge Volume Water Level - High				
a. Float Switch	NA	Q	R	1, 2, 5(j)
b. Level Transmitter/Trip Unit	S	Q(k)	R	1, 2, 5(j)
9. Turbine Stop Valve - Closure	NA	Q	R	1
10. Turbine Control Valve Fast Closure Valve Trip System Oil Pressure - Low	NA	Q	R	1
11. Reactor Mode Switch Shutdown Position	NA	R	NA	1, 2, 3, 4, 5
12. Manual Scram	NA	W	NA	1, 2, 3, 4, 5

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.
(b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.
(c) DELETED
(d) This calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥ ~~25%~~ 24% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER. Any APRM channel gain adjustment made in compliance with Specification 3.2.2 shall not be included in determining the absolute difference.
(e) This calibration shall consist of the adjustment of the APRM flow biased channel to conform to a calibrated flow signal.
(f) The LPRMs shall be calibrated at least once per 1000 effective full power hours (EFPH) using the TIP system.
(g) Verify measured core flow (total core flow) to be greater than or equal to established core flow at the existing recirculation loop flow (APRM % flow).
(h) This calibration shall consist of verifying the 6 ± 0.6 second simulated thermal power time constant.
(i) This item intentionally blank
(j) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.
(k) Verify the tripset point of the trip unit at least once per 92 days.
(l) Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.

TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level		
1) Low Low, Level 2	≥ -38.0 inches*	≥ -45.0 inches
2) Low Low Low, Level 1	≥ -129.0 inches*	≥ -136.0 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Reactor Building Exhaust Radiation - High	≤ $1x10^{-3}$μCi/cc	≤ $1.2x10^{-3}$μCi/cc
d. Manual Initiation	NA	NA
2. SECONDARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -38.0 inches*	≥ -45.0 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Refueling Floor Exhaust Radiation - High	≤ $2x10^{-3}$μCi/cc	≤ $2.4x10^{-3}$μCi/cc
d. Reactor Building Exhaust Radiation - High	≤ $1x10^{-3}$μCi/cc	≤ $1.2x10^{-3}$μCi/cc
e. Manual Initiation	NA	NA
3. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129.0 inches*	≥ -136.0 inches
b. Main Steam Line Radiation - High, High###	≤ 3.0 X full power background	≤ 3.6 X full power background
c. Main Steam Line Pressure - Low	≥ 756.0 psig	≥ 736.0 psig
d. Main Steam Line Flow - High	≤ ~~108.7~~ 162.8 psid	≤ ~~111.7~~ 169.3 psid

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 The end-of-cycle recirculation pump trip (EOC-RPT) system instrumentation channels shown in Table 3.3.4.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.4.2-2 and with the END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME as shown in Table 3.3.4.2-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to ~~30%~~ 24% of RATED THERMAL POWER.

ACTION:

a. With an end-of-cycle recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within 12 hours.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

   1. If the inoperable channels consist of one turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within 12 hours.

   2. If the inoperable channels include two turbine control valve channels or two turbine stop valve channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or take the ACTION required by Specification 3.2.3.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within one hour or take the ACTION required by Specification 3.2.3.

TABLE 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM[a]
1. Turbine Stop Valve - Closure	2[b]
2. Turbine Control Valve-Fast Closure	2[b]

[a] A trip system may be placed in an inoperable status for up to 6 hours for required surveillance provided that the other trip system is OPERABLE.

[b] This function shall be automatically bypassed when turbine first stage pressure is ~~≤ 159.7 psig~~ equivalent to THERMAL POWER less than ~~30%~~ 24% of RATED THERMAL POWER. ~~To allow for instrument accuracy, calibration and drift, a setpoint of ≤ 135.7 psig is used.~~

delete

delete

TABLE 3.3.6-2

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. ROD BLOCK MONITOR		
a. Upscale		
i. Flow Biased	≤ 0.66 (w-Δw) + 40%*	≤ 0.66 (w-Δw) + 43%*
ii. High Flow Clamped	≤ 106%	≤ 109%
b. Inoperative	NA	NA
c. Downscale	≥ 5% of RATED THERMAL POWER	≥ 3% of RATED THERMAL POWER
2. APRM		
a. Flow Biased Neutron Flux - Upscale	≤ 0.57 (w-Δw) + 53% ~~≤ 0.66(w-Δw) + 42%*~~	≤ 0.57(w-Δw) + 56% ~~≤ 0.66(w-Δw) + 45%*~~
b. Inoperative	NA	NA
c. Downscale	≥ 4% of RATED THERMAL POWER	≥ 3% of RATED THERMAL POWER
d. Neutron Flux - Upscale, Startup	≤ ~~12%~~ 11% of RATED THERMAL POWER	≤ ~~14%~~ 13% of RATED THERMAL POWER
3. SOURCE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	≤ 1.0 x 10^5 cps	≤ 1.6 x 10^5 cps
c. Inoperative	NA	NA
d. Downscale	≥ 3 cps	≥ 1.8 cps
4. INTERMEDIATE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	≤ 108/125 divisions of full scale	≤ 110/125 divisions of full scale
c. Inoperative	NA	NA
d. Downscale	≥ 5/125 divisions of full scale	≥ 3/125 divisions of full scale
5. SCRAM DISCHARGE VOLUME		
a. Water Level-High (Float Switch)	109'1" (North Volume) 108'11.5" (South Volume)	109'3" (North Volume) 109'1.5" (South Volume)
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW		
a. Upscale	≤ 111% of rated flow	≤ 114% of rated flow
b. Inoperative	NA	NA
c. Comparator	≤ 10% flow deviation	≤ 11% flow deviation
7. REACTOR MODE SWITCH SHUTDOWN POSITION	NA	NA

* The rod block function is varied as a function of recirculation loop flow (w) and Δw which is defined as the difference in indicated drive flow (in percent of drive flow which produces rated core flow) between two loop and single loop operation at the same core flow. The trip setting of the Average Power Range Monitor Rod Block function must be maintained in accordance with Specification 3.2.2.

3/4.3.11 OSCILLATION POWER RANGE MONITOR

LIMITING CONDITION FOR OPERATION

3.3.11 Four channels of the OPRM instrumentation shall be OPERABLE*. Each OPRM channel period based algorithm amplitude trip setpoint (Sp) shall be less than or equal to the Allowable Value as specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER.

ACTIONS

a. With one or more required channels inoperable:
   1. Place the inoperable channels in trip within 30 days, or
   2. Place associated RPS trip system in trip within 30 days, or
   3. Initiate an alternate method to detect and suppress thermal hydraulic instability oscillations within 30 days.

b. With OPRM trip capability not maintained:
   1. Initiate alternate method to detect and suppress thermal hydraulic instability oscillations within 12 hours, and
   2. Restore OPRM trip capability within 120 days.

c. Otherwise, reduce THERMAL POWER to less than ~~25%~~ 24% RTP within 4 hours.

SURVEILLANCE REQUIREMENTS

4.3.11.1 Perform CHANNEL FUNCTIONAL TEST at least once per 184 days.

4.3.11.2 Calibrate the local power range monitor once per 1000 Effective Full Power Hours (EFPH) in accordance with Note f, Table 4.3.1.1-1 of TS 3/4.3.1.

4.3.11.3 Perform CHANNEL CALIBRATION once per 18 months. Neutron detectors are excluded.

4.3.11.4 Perform LOGIC SYSTEM FUNCTIONAL TEST once per 18 months

4.3.11.5 Verify OPRM is enabled when THERMAL POWER is ≥ ~~30%~~ 26.1% RTP and recirculation drive flow ≤ the value corresponding to 60% of rated core flow once per 18 months.

4.3.11.6 Verify the RPS RESPONSE TIME is within limits. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip system. Neutron detectors are excluded.

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* When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated ACTIONS may be delayed for up to 6 hours, provided the OPRM maintains trip capability.

3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 RECIRCULATION SYSTEM

RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.4.1.1 Two reactor coolant system recirculation loops shall be in operation.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

a. With one reactor coolant system recirculation loop not in operation:

1. Within 4 hours:

   a) Place the recirculation flow control system in the Local Manual mode, and
   b) Reduce THERMAL POWER to ≤ ~~70%~~ 60.86% of RATED THERMAL POWER, and
   c) Increase the MINIMUM CRITICAL POWER RATIO (MCPR) Safety Limit per Specification 2.1.2, and
   d) Reduce the AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) limit to a value specified in the CORE OPERATING LIMITS REPORT for single loop operation, and
   e) Reduce the LINEAR HEAT GENERATION RATE (LHGR) limit to a value specified in the CORE OPERATING LIMITS REPORT for single loop operation, and
   f) Limit the speed of the operating recirculation pump to less than or equal to 90% of rated pump speed, and
   g) Perform surveillance requirement 4.4.1.1.2 if THERMAL POWER is ≤ 38% of RATED THERMAL POWER or the recirculation loop flow in the operating loop is ≤ 50% of rated loop flow.

2. Within 4 hours, reduce the Average Power Range Monitor (APRM) Scram Trip Setpoints and Allowable Values to those applicable for single recirculation loop operation per Specifications 2.2.1 and 3.2.2; otherwise, with the Trip Setpoints and Allowable Values associated with one trip system not reduced to those applicable for single recirculation loop operation, place the affected trip system in the tripped condition and within the following 6 hours, reduce the Trip Setpoints and Allowable Values of the affected channels to those applicable for single recirculation loop operation per Specifications 2.2.1 and 3.2.2.

3. Within 4 hours, reduce the APRM Control Rod Block Trip Setpoints and Allowable Values to those applicable for single recirculation loop operation per Specifications 3.2.2 and 3.3.6; otherwise, with the Trip Setpoint and Allowable Values associated with one trip function not reduced to those applicable for single recirculation loop operation, place at least one affected channel

*See Special Test Exception 3.10.4.

SURVEILLANCE REQUIREMENTS

4.4.1.1.1 With one reactor coolant system recirculation loop not in operation at least once per 12 hours verify that:

a. Reactor THERMAL POWER is ≤ ~~70%~~ 60.86% of RATED THERMAL POWER, and

b. The recirculation flow control system is in the Local Manual mode, and

c. The speed of the operating recirculation pump is less than or equal to 90% of rated pump speed.

4.4.1.1.2 With one reactor coolant system recirculation loop not in operation, within no more than 15 minutes prior to either THERMAL POWER increase or recirculation loop flow increase, verify that the following differential temperature requirements are met if THERMAL POWER is ≤ 38% of RATED THERMAL POWER or the recirculation loop flow in the operating recirculation loop is ≤ 50% of rated loop flow:

a. ≤ 145°F between reactor vessel steam space coolant and bottom head drain line coolant, and

b. ≤ 50°F between the reactor coolant within the loop not in operation and the coolant in the reactor pressure vessel, and

c. ≤ 50°F between the reactor coolant within the loop not in operation and the operating loop.

The differential temperature requirements or Specifications 4.4.1.1.2b and 4.4.1.1.2c do not apply when the loop not in operation is isolated from the reactor pressure vessel.

4.4.1.1.3 Each pump MG set scoop tube mechanical and electrical stop shall be demonstrated OPERABLE with overspeed setpoints less than or equal to 109% and 107%, respectively, of rated core flow, at least once per 18 months.

REACTOR COOLANT SYSTEM

JET PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.2 All jet pumps shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one or more jet pumps inoperable, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS*

4.4.1.2 All jet pumps shall be demonstrated OPERABLE as follows:

a. Each of the above required jet pumps shall be demonstrated OPERABLE prior to THERMAL POWER exceeding ~~25%~~ 24% of RATED THERMAL POWER and at least once per 24 hours by determining recirculation loop flow, total core flow and diffuser-to-lower plenum differential pressure for each jet pump and verifying that no two of the following conditions occur when the recirculation pumps are operating in accordance with Specification 3.4.1.3.

1. The indicated recirculation loop flow differs by more than 10% from the established pump speed-loop flow characteristics.

2. The indicated total core flow differs by more than 10% from the established total core flow value derived from recirculation loop flow measurements.

3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from the established patterns by more than 20%.

b. During single recirculation loop operation, each of the above required jet pumps in the operating loop shall be demonstrated OPERABLE at least once per 24 hours by verifying that no two of the following conditions occur:

1. The indicated recirculation loop flow in the operating loop differs by more than 10% from the established* pump speed-loop flow characteristics.

2. The indicated total core flow differs by more than 10% from the established* total core flow value derived from single recirculation loop flow measurements.

3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established* single recirculation loop patterns by more than 20%.

c. The provisions of Specification 4.0.4 are not applicable provided that this surveillance is performed within 24 hours after exceeding 24% ~~25%~~ of RATED THERMAL POWER.

*During startup following any refueling outage, baseline data shall be recorded for the parameters listed to provide a basis for establishing the specified relationships. Comparisons of the actual data in accordance with the criteria listed shall commence upon conclusion of the baseline data analysis. Single loop baseline data shall be recorded the first time the unit enters single loop operation during an operating cycle.

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2 Primary containment leakage rates shall be limited to:

a. An overall integrated leakage rate (Type A test) in accordance with the Primary Containment Leakage Rate Testing Program.

b. A combined leakage rate in accordance with the Primary Containment Leakage Rate Testing Program for all penetrations and all valves listed in Table 3.6.3-1, except for main steam line isolation valves*, valves which form the boundary for the long-term seal of the feedwater lines, and other valves which are hydrostatically tested per Table 3.6.3-1, subject to Type B and C tests.

c. *Less than or equal to 150 scfh per main steam line and less than or equal to 250 scfh combined through all four main steam lines when tested at 5 psig (leakage rate corrected to 1 Pa, ~~48.1~~ 50.6 psig).

d. A combined leakage rate of less than or equal to 10 gpm for all containment isolation valves which form the boundary for the long-term seal of the feedwater lines in Table 3.6.3-1, when tested at 1.10 Pa, ~~52.9~~ 55.7 psig.

e. A combined leakage rate of less than or equal to 10 gpm for all other penetrations and containment isolation valves in hydrostatically tested lines in Table 3.6.3-1 which penetrate the primary containment, when tested at 1.10 Pa, ~~52.9~~ 55.7 psig Δp.

APPLICABILITY: When PRIMARY CONTAINMENT INTEGRITY is required per Specification 3.6.1.1.

ACTION:

With:

a. The measured overall integrated primary containment leakage rate (Type A test) not in accordance with the Primary Containment Leakage Rate Testing Program, or

b. The measured combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steam line isolation valves*, valves which form the boundary for the long-term seal of the feedwater lines, and other valves which are hydrostatically tested per Table 3.6.3-1, subject to Type B and C tests not in accordance with the Primary Containment Leakage Rate Testing Program, or

c. The measured leakage rate exceeding 150 scfh per main steam line or exceeding 250 scfh combined through all four main steam lines, or

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*Exemption to Appendix "J" of 10 CFR 50.

SURVEILLANCE REQUIREMENTS (Continued)

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d. DELETED.

e. DELETED.

f. Main steam line isolation valves shall be leak tested at least once per 18 months.

g. Containment isolation valves which form the boundry for the long-term seal of the feedwater lines in Table 3.6.3-1 shall be hydrostatically tested at 1.10 P_a, ~~52.9~~ 55.7 psig, at least once per 18 months.

h. All containment isolation valves in hydrostatically tested lines in Table 3.6.3-1 which penetrate the primary containment shall be leak tested at least once per 18 months.

i. DELETED.

j. DELETED.

TABLE 3.6.3-1

PRIMARY CONTAINMENT ISOLATION VALVES

NOTES	NOTATION

1. Main Steam Isolation Valve leakage is not added to 0.60 La allowable leakage.*

2. Containment Isolation Valves are sealed with a water seal from the HPCI and/or RCIC system to form the long-term seal boundary of the feedwater lines. The valves are tested with water at 1.10 Pa, 55.7 ~~52.9~~ psig, to ensure the seal boundary will prevent by-pass leakage. Seal boundary liquid leakage will be limited to 10 gpm.

3. Containment Isolation Valve, Type C gas test at Pa, 50.6 ~~48.1~~ psig. Leakage added to entire system leakage. Allowable leakage for entire system limited to 0.60La.

4. Containment Isolation Valve, Type C water test at 1.10 Pa, 55.7 ~~52.9~~ psig delta P. Leakage added to entire system leakage. Allowable leakage for entire system limited to 10 gpm.

5. Containment boundary is discharge nozzle of relief valve, leakage tested during Type A test.*

6. Drywell and suppression chamber pressure and level instrument root valves and excess flow check valves, leakage tested during Type A.*

7. Explosive shear valves (SE-V021 through SE-V025) not Type C tested.*

8. Surveillances to be performed per Specification 3.6.1.8.

9. All valve I.D. numbers are preceded by a numeral 1 which represents a Unit 1 valve.

10. The reactor vessel head seal leak detection line (penetration J5C) excess flow check valve (BB-XV-3649) is not subject to OPERABILITY testing. This valve will not be exposed to primary system pressure except under the unlikely conditions of a seal failure where it could be partially pressurized to reactor pressure. Any leakage path is restricted at the source; therefore, this valve need not be OPERABILITY tested.

11. Containment Isolation Valve(s) are not Type C tested. Containment by-pass leakage is prevented since the line terminates below the minimum water level in the suppression chamber and the system is a closed system outside Primary Containment. Refer to Specification 4.0.5.

*Exemption to Appendix J of 10 CFR Part 50.

PLANT SYSTEMS

3/4.7.7 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.7 The main turbine bypass system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1 when THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER.

ACTION: ~~With~~ the main turbine bypass system inoperable, restore the system to OPERABLE status within 2 hours or reduce THERMAL POWER to less than or equal to ~~25%~~ 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.7.7 The main turbine bypass system shall be demonstrated OPERABLE at least once per:

a. 31 days by cycling each turbine bypass valve through at least one complete cycle of full travel, and

b. 18 months by:

   1. Performing a system functional test which includes simulated automatic actuation and verifying that each automatic valve actuates to its correct position.

   2. Demonstrating TURBINE BYPASS SYSTEM RESPONSE TIME meets the following requirements when measured from the initial movement of the main turbine stop or control valve:

      a) 80% of turbine bypass system capacity shall be established in less than or equal to 0.3 second.

      b) Bypass valve opening shall start in less than or equal to 0.1 second.

SPECIAL TEST EXCEPTIONS

3/4.10.2 ROD WORTH MINIMIZER

LIMITING CONDITION FOR OPERATION

3.10.2 The sequence constraints imposed on control rod groups by the rod worth minimizer (RWM) per Specification 3.1.4.1 may be suspended for the following tests provided that control rod movement prescribed for this testing is verified by a second licensed operator or other technically qualified member of the unit technical staff present at the reactor console:

a. Shutdown margin demonstrations, Specification 4.1.1.

b. Control rod scram, Specification 4.1.3.2.

c. Control rod friction measurements.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2 when THERMAL POWER is less than or equal to ~~10%~~ 8.6% of RATED THERMAL POWER.

ACTION:

With the requirements of the above specification not satisfied, verify that the RWM is OPERABLE per Specifications 3.1.4.1.

SURVEILLANCE REQUIREMENTS

4.10.2 When the sequence constraints imposed by the RWM are bypassed, verify:

a. That movement of the control rods from 75% ROD DENSITY to the RWM low power setpoint is limited to the approved control rod withdrawal sequence during scram and friction tests.

b. That movement of control rods during shutdown margin demonstrations is limited to the prescribed sequence per Specification 3.10.3.

c. Conformance with this specification and test procedures by a second licensed operator or other technically qualified member of the unit technical staff.

6.8.4.f Primary Containment Leakage Rate Testing Program

A program shall be established, implemented, and maintained to comply with the leakage rate testing of the containment as required by 10CFR50.54(o) and 10CFR50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program", dated September 1995, as modified by the following exception:

a. NEI 94-01-1995, Section 9.2.3: The first Type A test performed after April 12, 1994 shall be performed no later than April 12, 2009.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is ~~48.1~~ psig. 50.6

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.5% of primary containment air weight per day.

Leakage Rate Acceptance Criteria are:

a. Primary containment leakage rate acceptance criterion is less than or equal to 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are less than or equal to 0.6 L_a for Type B and Type C tests and less than or equal to 0.75 L_a for Type A tests;

b. Air lock testing acceptance criteria are:

1) Overall air lock leakage rate is less than or equal to 0.05 L_a when tested at greater than or equal to P_a,

2) Door seal leakage rate less than or equal to 5 scf per hour when the gap between the door seals is pressurized to greater than or equal to 10.0 psig.

The provisions of Specification 4.0.2 do not apply to the test frequencies specified in the Primary Containment Leakage Rate Testing Program.

The provisions of Specification 4.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

6.8.4.g. Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to MEMBER(S) OF THE PUBLIC from radioactive effluents as low as reasonably achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by operating procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

Attachment 3

LR-N05-0258
LCR H05-01

HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
ENVIRONMENTAL REPORT

HOPE CREEK GENERATING STATION
ENVIRONMENTAL REPORT
FOR EXTENDED POWER UPRATE

Prepared for:
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Prepared by:
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April 2005

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EXECUTIVE SUMMARY

This report presents an evaluation of the environmental impacts of the proposed Hope Creek Generating Station (HCGS or Station) thermal power uprate from 3,339[1] megawatts-thermal (MWt) to a maximum of 3,952 MWt. The intent of this report is to provide sufficient information for the Nuclear Regulatory Commission (NRC) to evaluate the environmental impacts of the Extended Power Uprate (EPU) in accordance with the requirements of 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions."

The environmental impacts of EPU are identified and compared against the environmental impacts that have been previously evaluated by the NRC (1984) in the Final Environmental Statement (FES) (1984) associated with the issuance of the HCGS operating license and in other related docketed correspondence. The environmental impacts identified by the NRC in the FES were based on conservative assumptions for source terms and other environmental parameters. Since initial operations, a variety of systematic environmental improvements have been implemented at HCGS that have further increased the margin of conservatism associated with these assumptions. By adjusting current plant operating parameters for extended power uprate effects, it will be readily demonstrated that the previous assumptions and conclusions concerning the environmental impact of HCGS operation continue to bound plant operation at EPU conditions. Plant activities involving design, construction, maintenance, and operation are conducted in strict compliance with environmental regulations and careful consideration of environmental consequences.

The HCGS extended power uprate is being implemented without consequential changes to the

[1] Hope Creek Operating License NPF-57 authorizes operation up to a maximum power level of 3,339 MWt, an increase granted in 2001 for which a Finding Of No Significant Impact was issued by NRC. This Environmental Assessment was conducted to include an evaluation of the cumulative environmental impacts of the 1.4% licensed power level increase from 3,293 MWt to 3,339 MWt granted in 2001 and the proposed Extended Power Uprate to 3,952 MWt.

plant systems that directly or indirectly interface with the environment. This evaluation demonstrates that the changes in environmental impacts of plant operation that will result from extended power uprate are not significant. The environmental impacts associated with extended power uprate are either well bounded by previously evaluated environmental impact analyses and criteria established by the NRC in the Final Environmental Statement or well bounded by other applicable regulatory criteria. As a result, approval of the extended power uprate will not significantly affect the environment.

1.0 INTRODUCTION

PSEG Nuclear LLC (PSEG) is committed to operating HCGS in an environmentally sound manner. Plant activities involving design, construction, maintenance, and operation are conducted in strict compliance with environmental regulations and careful consideration of environmental consequences. Numerous controls and modifications have been implemented to prevent and reduce impacts to the environment, and extensive environmental monitoring programs have been instituted at HCGS. In keeping with this important commitment and in accordance with regulatory requirements, PSEG has conducted a comprehensive environmental evaluation of the proposed extended power uprate, including the prior 1.4% rerate, from 3,293 MWt to 3,952 MWt.

This environmental evaluation is provided pursuant to 10 CFR 51.41, "Requirement to Submit Environmental Information," and is intended to fully support the NRC in complying with the requirements of Section 102(2) of the National Environmental Policy Act (NEPA), as amended, for the proposed change to the authorized operating power level at HCGS. Environmental report general requirements are outlined in 10 CFR 51.45. The evaluation provides information necessary to determine the environmental impact of those particular changes associated with the extended power uprate at HCGS to 3,952 MWt.

The environmental impact of operation at the present power level has been reviewed and determined to be acceptable by the NRC. In 1983, an Environmental Report (ER) was submitted by Public Service Electric and Gas Company (PSEG, 1983) to the NRC as part of the application for an operating license for HCGS. This report addressed the environmental impacts of construction and operation of the HCGS. In 1984, the ER was utilized by the NRC (1984) in preparing a Final Environmental Statement (FES) in fulfillment of the requirements of NEPA. The NRC subsequently issued operating license NPF-57 to HCGS authorizing operation up to a maximum power level of 3,293 MWt. In 2001, NRC authorized a licensed thermal power increase to 3,339 MWt and issued an "Environmental Assessment and Finding of No Significant Impact for Increase in Allowable Thermal Power Level".

This evaluation demonstrates that the extended power uprate will not result in a significant increase in the environmental impacts of operation of the HCGS. This evaluation was

performed against the originally licensed thermal power of 3,293 MWt as reviewed by the NRC to the EPU maximum of 3,952 MWt. The environmental impacts of HCGS operation with extended power uprate continue to be bounded by the FES or bounded by other appropriate and applicable regulatory criteria. This evaluation is submitted, in part, to fulfill the NRC (1996a) requirement to submit a "Supplement to the Applicant's Environmental Report" as documented in the Staff Position concerning the GE BWR EPU Program dated February 8, 1996.

This environmental report will assess the impact of EPU on the environment, compare changes to those presented in the FES or in more recent environmental reports, identify reasonable alternatives to the proposed EPU, and recommend a course of action.

2.0 PROPOSED ACTION AND NEED

2.1 DESCRIPTION OF PROPOSED ACTION

The proposed action is an amendment to the HCGS Operating License to increase the licensed core thermal power level to 3,952 MWt. The operational goal of this amendment is to increase electrical generating capacity. PSEG in conjunction with the plant designer, General Electric, has comprehensively evaluated the effects of an extended power uprate at HCGS. This environmental assessment was performed at a maximum increase in core thermal power of 3,952 MWt to ensure the conclusions bound the final power uprate. This evaluation concluded that sufficient safety and design margins exist such that an increase in the rated core thermal power to 3,952 MWt can be accomplished without adverse impact on the health and safety of the public and without significant impact on the environment.

Although the maximum authorized power level proposed by this action and evaluated for environmental impact herein is 3,952 MWt, the intent is to raise power level in increments. The final power level of HCGS will not exceed 3,952 MWt but may be less than that value.

HCGS is a Boiling Water Reactor (BWR) that operates in a direct thermodynamic cycle between the reactor and the turbine. Under extended power uprate conditions, thermodynamic processes are changed to extract additional work from the turbine. Simply put, extended power uprate involves installation of a higher efficiency turbine and an increase in the heat output of the reactor. This will support increased turbine inlet steam flow requirements and an increase in the heat dissipated by the condenser to support increased turbine exhaust steam flow requirements. In the turbine portion of the heat cycle, increases in the turbine throttle pressure and steam flow will result in a small increase in the heat rejected to the cooling tower. The environmental impacts of these operational changes are discussed herein.

Due to design and safety margins inherent in plant equipment, the proposed extended power uprate can be accomplished with relatively few modifications. The most significant changes involve replacement of the high pressure and low pressure turbines and replacement of the main transformers. Other minor modifications to support extended power uprate are routine in nature and are being conducted within the existing plant boundary.

The modifications are being accomplished by standard maintenance and modification processes that are similar to those performed during normal outages. The majority of plant systems will not require any significant modifications.

2.2 NEED FOR PROPOSED ACTION

Once per year, the North American Electric Reliability Council (NAERC) performs a forecast reliability assessment using information provided by the regional reliability councils such as Mid-Atlantic Area Council (MAAC) and the PJM Interconnection, L.L.C. (PJM). The 2004 net peak demand growth rate in the MAAC was 1.7% (NAERC, 2004) and the most current assessment includes a U.S. forecasted increase in expected customer peak demand, based on historical increases, of approximately 2.0% per year through the 2002 - 2011 planning period. The 2004 PJM Load Forecast Report forecasts normalized winter and summer increases of 1.5 to 1.7%, respectively, per year over the next ten years (PJM, 2004). These annual changes amount to an increased need of 8,300 to 10,700 MW over the next decade. The additional generating capacity provided by the EPU will help ensure that a reasonable operating margin for reliability is maintained in the MAAC and the PJM.

PSEG has determined the need for additional generation resources in its territory through a comparison of the projected load growth to the generation and possible power purchases. There are two significant aspects of maintaining a flexible and robust supply portfolio. The first is to obtain low cost power. The second is to maintain a portfolio with sufficient diversity to allow utilities to respond to changes in the underlying cost of power, owned or purchased. The increase in generating capacity of HCGS provides PSEG with lower cost power than can be obtained in the current and anticipated energy market. In addition, the increased generating capacity reduces exposure to potential cost increases in fossil fuel based alternatives. In a deregulated arena, the proposed EPU will displace approximately two 100 MWe gas turbines and the associated emissions impacts as discussed in Section 6.

Extended power uprate is an important step in improving the economic performance of HCGS under utility deregulation. The improved performance is accomplished by cost reductions in production and total bus bar cost per kilowatt hour (kWh). Therefore, extended power uprate

should enhance the value of HCGS as a generating asset. The extended uprate will help PSEG meet a projected need for additional capacity. The increased HCGS capacity when compared to new combustion turbine units, combined cycle units, and purchased power agreements, is a low cost option for maintaining a highly reliable power supply.

3.0 SOCIOECONOMIC IMPACTS

Extended power uprate does not affect the size of the HCGS workforce and does not have a material effect upon the labor force required for future outages. The HCGS contributions to local, state, and school taxes, both directly through taxation of PSEG and indirectly through taxation of the employees, vendors, and contractors, are of significant value to the local economy. The socioeconomic effects of implementing EPU at HCGS are, in part, dependent on the ability of PSEG to remain competitive in a deregulated market. Implementation of EPU is not the primary factor affecting the overall competitiveness of PSEG, but it is a factor that must be considered. PSEG has determined that, notwithstanding the uncertainty associated with deregulation, the favorable capital cost of the proposed EPU compared to new generating capacity, and the reduction in incremental costs that result from EPU as compared to new generation facilities, make the EPU project attractive. In addition, the investment associated with the proposed EPU will result in increased revenues, thus enhancing the value of HCGS as a provider of electricity and allow PSEG to remain a strong partner within the community and the State of New Jersey. The direct benefit of an extended power uprate to PSEG customers is that the program will supply up to an additional 213 MWe of reliable electrical generating capacity.

A quantitative study of environmental costs of alternatives is not necessary to recognize that significant environmental benefits can be derived from extended power uprate when compared to other options of adding capacity. As demonstrated herein, extended power uprate does not result in significant environmental costs. Unlike fossil fuel plants, HCGS does not routinely emit significant amounts of Sulfur Dioxide ($S0_2$), Nitrogen Oxide (NOx), Carbon Dioxide (CO_2) or other atmospheric pollutants during normal operation. Routine operation of HCGS at extended power uprate conditions will not contribute to greenhouse gas emissions, ground level ozone (smog), or acid rain.

The environmental effects of the fuel cycle and of transportation of fuel and waste are very small as discussed in Section 5.0. While the project will produce additional spent nuclear fuel, the added amount is not appreciable and can be accommodated by the facility.

Based upon the discussion above, it is reasonable to conclude the HCGS extended power uprate project provides an economic advantage to other alternatives for added generation. Extended power uprate involves effective utilization of an existing asset with negligible environmental impact and is the preferable option to secure additional generation.

4.0 NON-RADIOLOGICAL ENVIRONMENTAL IMPACTS

4.1 TERRESTRIAL RESOURCES

4.1.1 Threatened and Endangered Species

The FES (NRC, 1984) noted that the geographic range of several species listed as endangered by the Federal Government include the state of New Jersey. Some terrestrial species (e.g., small whorled pogonia) are known to occur in New Jersey but not on or near the HCGS and its associated transmission facilities. However, the state endangered bald eagle and peregrine falcon occasionally occur as non-breeding visitors near the HCGS, while the state endangered osprey commonly nests on transmission towers near HCGS (NRC, 1984). Bald eagles and peregrine falcons do nest in other areas of Salem County. Table 4-1 presents a current list of threatened and endangered species potentially occurring near HCGS and their status (NJDEP, 2005; PSEG, 2003).

The generic assessment of power plants showed that neither cooling system operations nor electric power transmission lines associated with nuclear power plants have significant adverse impacts on any threatened or endangered species (NRC, 1996b). The FES (NRC, 1984) concluded that the operation of HCGS will not have any adverse impacts on terrestrial endangered and threatened species. An assessment conducted my the National Marine Fisheries Service (NMFS, 1993) in consultation with the Nuclear Regulatory Commission (NRC, 1993) under Section 7 of the Endangered Species Act (ESA) determined that "continued operation of the Hope Creek Generating Station will not affect listed species" under the ESA. The extended power uprate will not change the physical location or dimensions of HCGS's structures. The conclusion for the extended power uprate is the same since it will not have any additional impact on these species or their habitats.

4.1.2 Terrestrial Biota

The terrestrial biota of the HCGS and surrounding area were described in the ER (PSEG, 1983) and FES (NRC, 1984). The FES identified that HCGS is located on Artificial Island, which consists of dredge spoils, has only low quality habitats for wildlife, and thus is not an important

natural resource area. Vegetation near the HCGS is predominately found in tidal marsh, upland field, and upland woodland habitats.

The proposed extended power uprate will not produce a significant increase (approximately 9%) in existing cooling tower salt drift. An NJDEP (1980) study estimated that the two cooling towers proposed at that time for the two units at HCGS might annually add up to an additional 0.2 lb/acre of salt deposition on the nearest farm. Subsequently, only one unit and one cooling tower were built at HCGS. To put the cooling tower salt deposition rate for one tower (0.1 lb/acre) into perspective, NJDEP stated that the annual rate of deposition due to crop fertilization is about 4.0 lb/acre, and approximately 375 lb/acre due to natural seasalt deposition along the New Jersey ocean coast. Salt deposition studies performed in the vicinity of HCGS during 1987-1989 confirmed that the highest salt deposition rates were well below the threshold to reduce agricultural plant productivity (WCC, 1989). The activities associated with the extended power uprate will not change the terrestrial flora and fauna and associated habitats in the vicinity of HCGS because the estimated 9% increase in the salt deposition rates from the HCGS cooling tower as a result of the extended power uprate is well below salt deposition rates that cause adverse effects (NJDEP, 1980; WCC, 1989). Therefore, the conclusion reached in the FES (NRC, 1984) that the operation of HCGS would not have any adverse impacts on terrestrial biota remains valid for the extended power uprate.

Table 4-1

Threatened and Endangered Species Potentially Occurring near HCGS.

Common Name	Scientific Name	State Status[2]	Federal Status[3]
Bald eagle	*Haliaeetus leucocephalus*	E/T	LE/LT[4]
Peregrine falcon	*Falco peregrinus*	E	LE/SA
Osprey	*Pandion haliaetus*	T/U	
Northern harrier	*Circus cyaneus*	E/S	
Red shouldered hawk	*Buteo lineatus*	E/T	
Grasshopper sparrow	*Ammodramus savannarum*	T	
Savannah sparrow	*Passerculus sandwichenis*	T	
Vesper sparrow	*Pooectes gramineus*	E/T	
Sedge wren	*Cistothorus platenis*	E	
Pied-billed grebe	*Podilymbus podiceps*	E	
Yellow-crowned night heron	*Nyctanassa violacea*	T	
Shortnose sturgeon	*Acipenser brevirostrum*	E	E
Atlantic loggerhead turtle	*Caretta caretta*	E	T
Atlantic green turtle	*Chelonia mydas*	T	T
Kemp's ridley turtle	*Lepidochelys kempi*	E	E

[2] State status codes: E = Endangered; T = Threatened; S = Stable; U = Undetermined; / = indicates dual status, first status refers to state breeding population and second status refers to non-breeding population.
[3] Federal status codes: LE = Taxa formerly listed as endangered; LT = Taxa formerly listed as threatened; LE/SA = Listed Endangered/Similarity of Appearance.
[4] Federal Status as listed in the New Jersey Department of Environmental Protection Natural Heritage Program (NHP) database. A Final Rule reclassifying the status of the bald eagle from endangered to threatened was published by FWS in the Federal Register on July 12, 1995 with an effective date of August 11, 1995.

4.1.3 Land Use

The extended power uprate does not change the present HCGS land use. Based on the U.S Census reports, the population in Salem County has declined slightly from 1980 to 2000 with a shift in population from the City of Salem to other areas in the county like Lower Alloways Creek (Table 4-2). However, there are no plans to build facilities or materially alter the land use to support extended power uprate activities. Except for transportation of equipment and routine disposal of waste, extended power uprate maintenance activities are confined to the area within the site boundary. Extended power uprate does not affect the storage requirements for above ground or below ground tanks. Lands located outside the site boundary will not be affected by extended power uprate activities. Consistent with the FES the extended power uprate does not involve changes to any aesthetic resources and does not involve any impacts to lands with historical or archaeological significance.

The extended power uprate is not expected to require additional low-level radioactive waste storage facilities. The replaced turbine components will be decontaminated as necessary, and recycled to the extent possible, or transferred to an approved disposal facility.

4.1.4 Transmission Facilities

At present, three transmission lines serve HCGS. Two pre-existing transmission lines were disconnected from the Salem Generating Station and routed into the HCGS (i.e., Hope Creek-New Freedom and Hope Creek-Red Lion). A third line approximately 1,000 feet long connects HCGS to the Salem Generating Station within the PSEG site boundary. No changes in operating transmission or power line right of way are required to support extended power uprate. However, higher main transformer capacity will be necessary to deliver the additional power to the offsite grid. This will be accomplished by replacing the existing transformers that do not meet these capacity requirements.

Extended power uprate does not increase the probability of "corona" or electrical shock from primary or secondary currents. In addition, the transmission lines are designed in accordance with the applicable shock prevention provisions of the National Electric Safety Code (NESC).

There is no scientific consensus regarding the health effects, if any, of exposure to electric and magnetic fields, collectively referred to as electromagnetic fields (EMF) produced by operating transmission lines. Chronic effects of EMF on humans are not quantified at this time and no significant impacts to terrestrial biota have been identified (NRC, 1996b). Subsequent review of the potential health effects of EMF by organizations such as the American Conference of Governmental Industrial Hygienists (ACGIH), the International Commission on Non-Ionizing Radiation Protection (ICNIRP), and the International Agency for Research on Cancer (IARC) have identified no deleterious human effects.

The increased generator output at HCGS will cause a corresponding current, and thus magnetic field, increase in the onsite transmission line between the HCGS main generator and the plant substation. This transmission line is located within the outer fenced boundary of the plant where public access is prohibited. Furthermore, the extended power uprate does not involve significant increases in exposure to electromagnetic fields from transmission lines and therefore, the conclusions in the FES (NRC, 1984) relative to the effects of EMF remain valid.

4.1.5 Noise

The extended power uprate will not result in significant changes to the character, sources, or energy of noise generated at HCGS. The new equipment necessary to implement extended power uprate will be installed within existing plant buildings. No significant increase in ambient noise levels is expected within the plant. This includes the upgraded turbines, which will operate at the same speed as the original equipment. The nearest resident is over 3 miles from HCGS. The NRC staff concluded that area residents would not be adversely affected by noise resulting from Station operation (NRC, 1984). The Environmental Report and FES conclusions for noise levels remain relevant for extended power uprate conditions.

Table 4-2. Population Changes in the Project Area[a]

	1980	2000	% Change

New Jersey	7,364,823	8,414,350	14.2
Salem County	64,676	64,285	-0.6
Lower Alloways Creek (LAC)	1,547	1,851	19.7
City of Salem	6,959	5,857	-15.8
HOUSING UNITS			
Salem County	22,476	26,158	16.4
LAC	572	730	27.6
City of Salem	2,830	2,863	1.2
[a] United States Census Reports 1980 and 2000.			

4.2 AQUATIC RESOURCES

4.2.1 Threatened and Endangered Species

Table 4-1 presents a current list of threatened and endangered species potentially occurring near HCGS and their status (PSEG, 2003). The shortnose sturgeon (*Acipenser brevirostrum*) is listed as endangered by both the United States Fish and Wildlife Service (FWS) and the State of New Jersey. A significant portion of New Jersey's shortnose sturgeon occurs in the upper tidal Delaware River, which is a substantial distance from HCGS. NRC (1980) and National Marine Fisheries Service (NMFS) staff (Leitzell, 1980) concluded that the operation of HCGS would not jeopardize the continued existence of the shortnose sturgeon.

Sea turtles have been observed and captured in the vicinity of HCGS, including two federally listed threatened species, the Atlantic loggerhead turtle (*Caretta caretta*) and the Atlantic green turtle (*Chelonia mydas*), and one endangered species, the Kemp's ridley turtle (*Lepidochelys kempi*). The three turtle species spend almost their entire lives in the sea and their occurrence in the vicinity of HCGS is relatively infrequent.

The FES (NRC, 1984) concluded that the operation of HCGS will not have any adverse impacts on aquatic endangered and threatened species. More recently, the NMFS (1993), in consultation with NRC, concluded in its Section 7 Biological Opinion that "...No impingements have been recorded at the Hope Creek Generating Station. Thus, besides the normal cleanings, monitoring is no longer necessary." The conclusion for the extended power uprate is consistent with the conclusions presented above since it will not have any additional impact on these species or their habitats.

4.2.2 Cooling Water Withdrawal

The volume of water withdrawn by the service water system for cooling and ultimately providing makeup to HCGS's closed cycle cooling system are relatively low, approximately 67 million gallons per day (MGD) during normal operations. Water usage at HCGS during normal operations accounts for less than 0.03 percent of the average tidal flow of the estuary of about 259,000 MGD. Based on these factors, the number of organisms susceptible to impingement and entrainment is relatively low. Impingement and entrainment effects were evaluated in the FES for full power operation as having minimal impact to the aquatic community of the Delaware River. In addition, the New Jersey Department of Environmental Protection (NJDEP, 2002) determined that that the location, design, construction, and capacity of HCGS's cooling water intake structure continues to reflect the best technology available (BTA) for minimizing adverse environmental impact. This conclusion is consistent with USEPA's final section 316(b) rule for existing facilities (Federal Register, July 9, 2004). Extended power uprate does not increase the intake flow requirements of the plant nor change the construction of the cooling water intake structure and, therefore, these evaluations remains valid.

4.3 AIR QUALITY

4.3.1 Cooling Tower Air Contaminant Emissions

PSEG has been issued an Air Operating Permit from NJDEP in accordance with New Jersey Administrative Code (N.J.A.C.) 7:27-22 and Title V of the Clean Air Act for operation of the HCCT. The Permit limits emissions of particulates to no greater than 29.4 pounds per hour. PSEG provides annual reports to the NJDEP demonstrating compliance with this limitation.

As discussed in section 4.3.2 below, the emission rate of PM from the cooling tower is dependent on the circulating water flow rate, the drift rate, and the concentration of total dissolved solids (TDS) in the circulating water. The circulating flow rate and the drift rate are not being changed by the EPU. The concentration of TDS in the makeup water is highly variable and depends primarily on the tidal hydrodynamics of the Delaware Estuary, hydrological conditions (namely, precipitation and runoff), meteorological conditions and the salinity of the Delaware Estuary. Salinity usually is between 0 and 20 parts per thousand (ppt) and typically exceeds 6 ppt during periods of low freshwater inflow in summer. Evaporation rates are seasonally variable and tend to be highest in the summer (approximately 13,000 gpm) and lowest in the winter (approximately 10,000 gpm). The wide variability in the concentration of TDS in the makeup water and of the evaporation rate can introduce considerable variability in the short-term emissions of particulate matter from HCCT.

Calculations indicate that particulate emissions from the HCCT could increase as a result of the extended power uprate to a maximum of 42.0 pounds per hour. This maximum potential emission rate exceeds the emissions rate specified in the air permit for the facility and is in excess of the standards set at N.J.A.C. 7:27-6.2, which limits the emissions of particulate matter from any process to 30 pounds per hour. Increased particulate air emissions, however, will not occur until the phase of the EPU where reactor thermal power is increased. PSEG has discussed this with the NJDEP and is primarily pursuing two parallel paths.

First, NJDEP is in the process of a regulatory revision to the N.J.A.C. 7:27-6.2 limit. The current limit of 30 pounds per hour is based on the emission of 0.02 grains per standard cubic foot and a maximum air flow of 175,000 standard cubic feet per minute (scfm). The regulatory revision is

anticipated to allow a limitation based on the air flow, substituting a 0.015 grains per standard cubic foot basis or a similar metric, and require atmospheric modeling to demonstrate a lack of negative impact. The air flow from the HCCT is approximately 44 million scfm and atmospheric modeling indicates that an emission rate of 42.0 pounds per hour would not have a negative impact. The regulatory revision is currently anticipated to be issued in 2006.

In parallel, PSEG has submitted a request for a variance from the 30 pound per hour limitation. The New Jersey regulations at N.J.A.C. 7:27-6.5 allow for a request for a variance from the 30 pounds per hour limitation when the applicant believes that advances in the art of control for the kind and amount of particles emitted has not developed to a degree that would enable the 30 pounds per hour to be achieved. PSEG has determined from discussions with a manufacturer of cooling towers that the state of the art for emissions control has not developed beyond that installed in the HCCT. Research of the USEPA's RACT/BACT/LAER Database identified that the HCCT emission rate is 59% lower than the typical result in the database and 18% lower than the lowest entry in the database. Therefore, the HCCT meets the requirements of N.J.A.C. 7:27-6.5 for obtaining a variance from the 30 pound per hour particulate emission limitation. PSEG will not operate the HCCT above the particulate emission limitations imposed by NJDEP.

Additionally, the initial evaluation of cooling tower air contaminant emissions from HCGS was conducted considering two cooling towers and found no adverse environmental effects. HCGS was constructed with only one cooling tower, the other unit was cancelled. This provides additional conservatisms in demonstrating the air emissions after the EPU will be bounded by the FES.

4.3.2 Prevention of Significant Deterioration

The USEPA's Prevention of Significant Deterioration (PSD) regulations are codified at 40 CFR 52.21. Because, HCGS is more than 10 km from a Class I area, the actual increases that trigger a PSD review are defined at 40 CFR 52.21(b)(23)(i). These regulations would apply if the extended power uprate were a physical change or change in the method of operation that resulted in a significant net emissions increase of a criteria pollutant. A significant net emissions increase of total suspended particulates (TSP) or PM_{10} (equivalent aerodynamic particle sizes less than 10 microns in diameter) occurs when comparison of the baseline actual

emissions with the projected-actual emissions yields an emissions increase of 15 tons or more per year (tpy)of PM_{10} or 25 tons or more per year of TSP. PM_{10} is characterized by equivalent aerodynamic particle sizes less than 10 microns in diameter. TSP is characterized by all particulate matter, including PM_{10}. PSEG has concluded that the PSD regulations do not apply to the EPU and the United Stated Environmental Protection Agency (USEPA) has concurred with that determination (USEPA 2004b).

HCGS is a major existing source that is located in an area that is designated "attainment" or "unclassified" for TSP and PM_{10}. Therefore, annual particulate increases resulting from physical changes or changes in the method of operation at HCGS must be evaluated with respect to PSD regulations.

The EPU is expected to increase emissions of particulate matter (PM) from the existing natural draft cooling tower. The PM is assumed to be characterized by equivalent aerodynamic particle sizes less than 10 microns in diameter (PM_{10}). That is, all emissions are conservatively assumed to be PM_{10} for the purpose of the PSD non-applicability determination. The PSD significant emission increase threshold for TSP is greater than that for PM_{10} (25 tpy for TSP versus 15 tpy for PM_{10}). If the particulate emission increase resulting from the EPU, considering the entire particulate mass emitted without respect to particle size, is less than the PM_{10} threshold, there is no possibility of exceeding the 25 tpy threshold for TSP.

HCGS uses a closed cycle cooling water system (CWS) to dissipate waste heat to the atmosphere. The CWS consists of a natural draft cooling tower (HCCT), circulating water pumps, condensers, service water pumps, a circulating water line, and a blowdown line. Circulating water pumps force a large cooling water flow through the condensers, which raise the temperature of the cooling water. The heated water is passed to the HCCT, which lowers the temperature primarily through evaporation. A very small percentage (< 0.0005%) of the circulating water is lost as drift that is carried out of the tower by the natural draft. The drift contains dissolved solids that are present in the circulating water.

The emission rate of PM from the cooling tower is dependent on the circulating water flow rate, the drift rate, and the concentration of total dissolved solids (TDS) in the circulating water. The total design flow rate of the circulating water pumps is 552,000 gpm. The design drift rate is

0.0005% of the circulating water flow rate. Test data and other measurements show that the actual circulating water flow rate is approximately 612,000 gpm while the drift rate is only 0.00041% of the circulating water flow. The concentration of TDS in the circulating water varies with the concentration of TDS in the makeup water, the service water (or makeup) flow rate, and the evaporation from the tower. The concentration of TDS in the makeup water is highly variable and depends primarily on the tidal hydrodynamics of the Delaware Estuary, hydrological conditions (namely, precipitation and runoff), meteorological conditions, and the salinity of the Delaware Estuary. Salinity usually is between 0 and 20 parts per thousand (ppt) and typically exceeds 6 ppt during periods of low freshwater inflow in summer. Service water flow rates typically range from approximately 36,500 gpm (when intake temperatures are less than 70°F) to 51,500 gpm when the estuarine water is warmer. Evaporation rates are seasonally variable and tend to be highest in the summer (approximately 13,000 gpm) and lowest in the winter (approximately 10,000 gpm). The concentration of TDS in the circulating water increases as the evaporation rate increases and/or the service water flow rate decreases. The wide variability in the concentration of TDS in the makeup water and of the evaporation rate can introduce considerable variability in the short-term and annual emissions of particulate matter from HCCT.

The comparison of baseline PM_{10} actual emissions (53.5 tpy) with the projected-actual emissions (63.7 tpy) yields an emissions increase of 10.2 tpy for PSD applicability purposes. Actual emissions of other criteria pollutants to the atmosphere will not change as a result of the EPU. Therefore, the planned EPU does not trigger Prevention of Significant Deterioration regulations.

4.4 HYDROLOGY EFFECTS

HCGS operates under New Jersey Pollutant Discharge Elimination System (NJPDES) Permit No. NJ 0025411, with an effective date of March 1, 2003, that covers the following discharges and typical daily average flows, as depicted on Figure 4-1:

- DSN 461A, combination of all non-stormwater wastewater components, primarily cooling tower blowdown (46.9 MGD)
- DSN 461C, internal monitoring point for low volume and oily waste system (0.04 MGD)

- DSN 462B, internal monitoring point for sewage treatment system (0.02 MGD)
- DSN 465A (formerly 462A), north stormwater drain (0.24 MGD)
- DSN 463A, south stormwater drain (0.51 MGD)
- DSN 464A, perimeter stormwater drain (0.41 MGD)

All of these discharges ultimately flow to the Delaware River.

4.4.1 Cooling Tower Effluent

The HCGS circulating water system (CWS) transports excess heat from the condensers to the cooling tower for dissipation. The CWS is a closed cycle cooling water system and the circulating water is re-circulated within the CWS. The CWS provides an operating volume of about 11 million gallons of water and about 9 million gallons resides in the cooling tower basin. There is an evaporative loss of approximately 10 to 13 MGD (See Figure 4-1) from the natural draft cooling tower and a continuous blowdown is used to control the solids concentration. Makeup water to replace the evaporative loss and continuous blowdown is provided by the service water system (See Section 4.2.2 above).

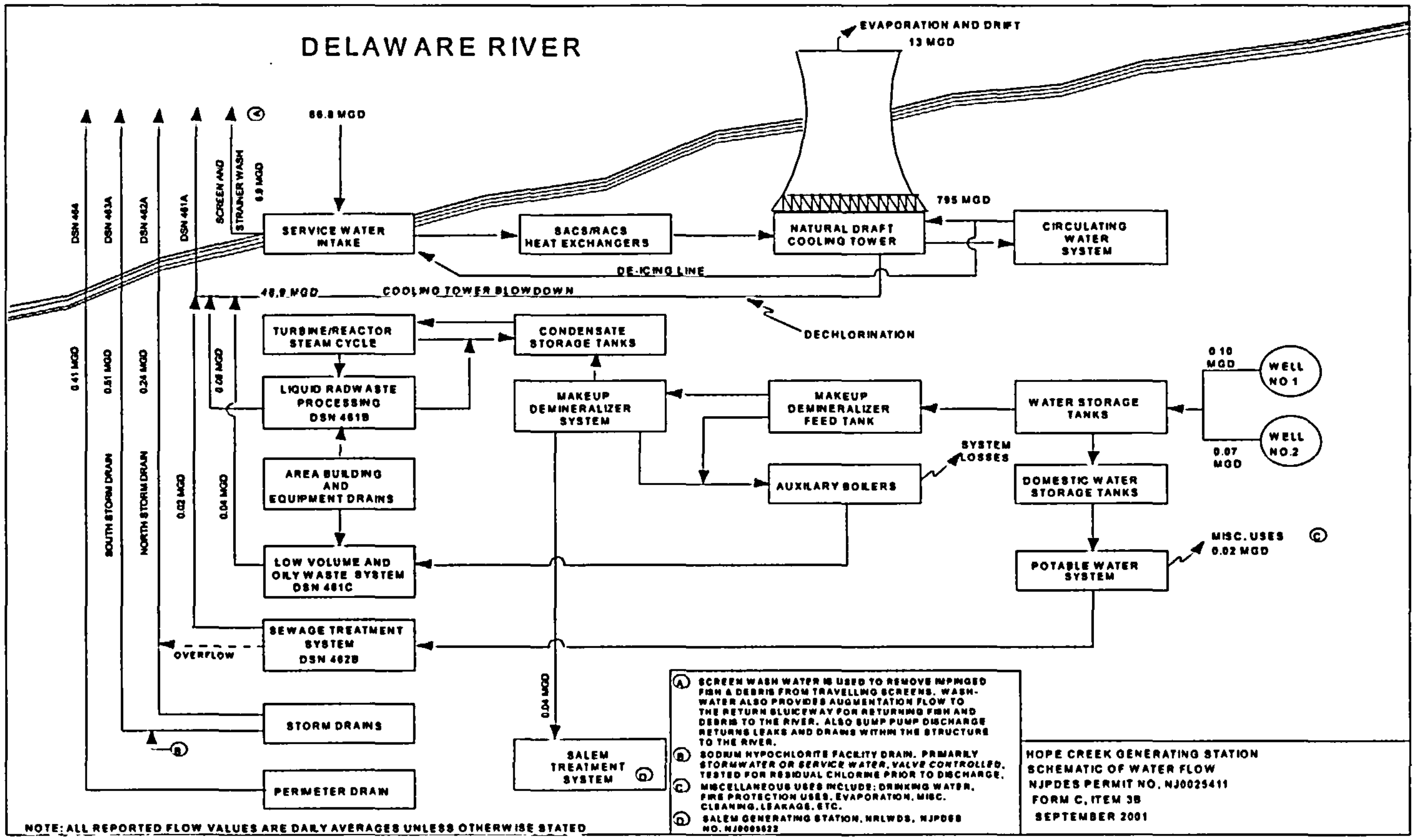
DELAWARE RIVER
EVAPORATION AND DRIFT
13 MGD
66.8 MGD
DSN 464
DSN 463A
DSN 462A
DSN 461A
SCREEN AND STRAINER WASH
6.9 MGD
SERVICE WATER INTAKE
SACS/RACS HEAT EXCHANGERS
795 MGD
NATURAL DRAFT COOLING TOWER
CIRCULATING WATER SYSTEM
DE-ICING LINE
48.9 MGD
COOLING TOWER BLOWDOWN
DECHLORINATION
TURBINE/REACTOR STEAM CYCLE
CONDENSATE STORAGE TANKS
0.41 MGD
0.51 MGD
0.24 MGD
0.08 MGD
LIQUID RADWASTE PROCESSING DSN 461B
MAKEUP DEMINERALIZER SYSTEM
MAKEUP DEMINERALIZER FEED TANK
WATER STORAGE TANKS
0.10 MGD
WELL NO 1
WELL NO.2
0.07 MGD
SYSTEM LOSSES
AUXILIARY BOILERS
DOMESTIC WATER STORAGE TANKS
AREA BUILDING AND EQUIPMENT DRAINS
SOUTH STORM DRAIN
NORTH STORM DRAIN
0.02 MGD
0.04 MGD
MISC. USES
0.02 MGD
LOW VOLUME AND OILY WASTE SYSTEM DSN 461C
POTABLE WATER SYSTEM
SEWAGE TREATMENT SYSTEM DSN 462B
OVERFLOW
0.04 MGD
STORM DRAINS
SALEM TREATMENT SYSTEM
PERIMETER DRAIN
A SCREEN WASH WATER IS USED TO REMOVE IMPINGED FISH & DEBRIS FROM TRAVELLING SCREENS. WASH-WATER ALSO PROVIDES AUGMENTATION FLOW TO THE RETURN SLUICEWAY FOR RETURNING FISH AND DEBRIS TO THE RIVER. ALSO SUMP PUMP DISCHARGE RETURNS LEAKS AND DRAINS WITHIN THE STRUCTURE TO THE RIVER.
B SODIUM HYPOCHLORITE FACILITY DRAIN. PRIMARILY STORMWATER OR SERVICE WATER, VALVE CONTROLLED. TESTED FOR RESIDUAL CHLORINE PRIOR TO DISCHARGE.
C MISCELLANEOUS USES INCLUDE: DRINKING WATER, FIRE PROTECTION USES, EVAPORATION, MISC. CLEANING, LEAKAGE, ETC.
D SALEM GENERATING STATION, NRLWDS, NJPDES NO. NJ0005622
HOPE CREEK GENERATING STATION
SCHEMATIC OF WATER FLOW
NJPDES PERMIT NO. NJ0025411
FORM C, ITEM 3B
SEPTEMBER 2001
NOTE: ALL REPORTED FLOW VALUES ARE DAILY AVERAGES UNLESS OTHERWISE STATED

Figure 4-1

The cooling tower effluent (DSN 461A) is monitored for flow, temperature, heat rate, pH, chlorine produced oxidants (CPOs), and total organic carbon (TOC) as required by the NJPDES permit. NRC (1984) noted that dilution by river and tidal flow as well as CPO demand by the river could reduce the amount of CPOs released to the Delaware River below the NJPDES permit limits. HCGS has also installed a dechlorination system, utilizing ammonium bisulfite, to further reduce CPO concentrations and ensure compliance with the NJPDES permit. Toxic amounts of other chemicals in the effluent are not permitted and the non-toxic effect of the discharges has been confirmed by acute and chronic toxicity tests performed during 1998 through 2001 (see Attachment A).

Thermal effluent limitations imposed by the Delaware River Basin Commission (DRBC) in the NJPDES permit require that the net temperature increase of the Delaware River not be greater than 2.2°C from September to May and not greater than 0.8°C from June to August. These limitations apply outside a heat dissipation area (HDA) no larger than 2,500 ft upstream or downstream or 1,500 ft outshore from the point where the effluent enters the river. The FES (NRC, 1984) concluded that the shoreline discharge should not adversely affect shore zone biota because of the large tidal influence (amplitude of 6.6.- 8.5 ft and high tidal flow of about 400,000 cfs), which dilutes, mixes, and rapidly dissipates the thermal discharges from HCGS. Mobile resident and migratory fish that come in contact with any portion of the thermal plume with temperatures higher than their preference temperatures should be able to readily avoid the plume. Cold shock to aquatic organisms results when the warm water discharge from a plant abruptly stops due to an unplanned shutdown. The probability of an unplanned shutdown is independent of extended power uprate. Although extended power uprate will slightly increase the discharge temperature, HCGS will continue to be operated within and not exceed the current NPDES 24-hour average temperature limitation of 97.1° F. The recent hydrothermal modeling analysis for the HCGS EPU project (Najarian Associates, 2003), illustrates that discharge will be in compliance with the DRBC water quality standards for water temperature at the edge of the associated seasonal HDAs. An analysis conducted by PSEG and appended to the hydrothermal modeling analysis report demonstrates that the 97.1° F effluent limitation of the NJPDES Permit will be met. Consequently, the increase in thermal impacts to aquatic organisms will not be significant, and the total impact will continue to be bounded by the FES.

4.4.2 Other Effluents

The discharge flow from DSN 461A also consists of other minor non-radiological waste stream contributions from the Low Volume and Oily Waste System (DSN 461C, 0.04 MGD) and the Sewage Treatment System (DSN 462B, 0.02 MGD), as well as the radioactive liquid waste system. The low volume oily waste system collects and treats potentially oily wastewater from the area, building, and equipment drains throughout the site as well as auxiliary boiler blowdown, and miscellaneous stormwater sources. The sewage treatment system treats domestic wastewater from HCGS and the adjacent Salem Generating Station. The NJPDES permit specifies internal effluent limitations and monitoring for these systems before discharge via DSN 461A.

The North Yard Drain (DSN 465A, 0.24 MGD) collects and discharge site drainage from the facility parking lots, warehouse roof drain, loading ramp catch basins, auxiliary boiler roof drains, fire water pumphouse, No.2 Reactor Building roof and area drains, materials center area and roof drains, construction and excavation dewatering, and runoff from miscellaneous sources.

The South Yard Drain (DSN 463A, 0.51 MGD) collects and discharges site drainage from the Security Center roof, drain, and parking lot, roof and area drains from the Administration Building, Auxiliary Boiler, Turbine Building, Reactor Building, Materials Center, and Services Facility Building, safety shower, as well as the Chlorine Structure drains, service water valve pit, dewatering sump, construction and excavation dewatering, and runoff from other miscellaneous sources.

The Perimeter Drain (DSN 464A, 0.41 MGD) collects and discharges site drainage from the access road area, Administration Building roof drains and parking lots, Combo Shop roof drains, catch basins in undeveloped portions of the site, groundwater, and natural drainage from the adjacent marshes and immediate areas external to HCGS.

The NJPDES permit specifies the required controls for these three stormwater outfalls to include a Stormwater Pollution Prevention Plan containing Best Management Practices, which helps to ensure that the discharges will not have an adverse impact on Delaware River water quality.

As noted by the NRC (1996b), the impacts of discharges should be considered of small significance if water quality criteria (e.g., NPDES permits) are not consistently violated. The EPU will not create any condition that would cause a violation of the NJPDES Permit.

4.4.3 Groundwater

Two, approximately 815 ft deep wells provide domestic and process water to the HCGS. The wells are permitted by NJDEP (2000) and DRBC to supply groundwater from the Raritan aquifer at a maximum withdrawal rate of 700 gpm or 30.2 million gallons per month (mgm) per well. The NJDEP Staff Report (2000) accompanying the most recent permit states that PSEG is currently in compliance with all permit conditions. No wastes from HCGS are disposed of through underground injection to ground water. The proposed extended power uprate will not increase the use of groundwater or change the limits in the current water allocation permit. Therefore, the conclusions of the FES relative to groundwater remain valid for the extended power uprate.

4.4.4 Surface Water

HCGS cooling and service water supply is obtained from the Delaware River. The Station's service water system withdraws about 67 MGD. Approximately 7 MGD is used for intake screen wash water and strainer backwash. The Service Water is used as makeup water for the cooling tower. The cooling tower system evaporates approximately 13 MGD and returns about 47 MGD through the cooling tower blowdown. The EPU will not increase the amount of water withdrawn from the Delaware River. Consumptive use of surface water is regulated by the DRBC under a water use contract and will not substantively change as a result of the EPU. Based on over 16 years of monitoring, Operation of HCGS has not been reported to have adversely affected the water quality or water quantity of the Delaware River. Furthermore, there is no indication that water withdrawals or discharges from the once-through cooling Salem Generating Station and adjacent HCGS have caused any detrimental effects to the aquatic biota in the Delaware River (PSEG, 1999).

Water quality monitoring programs have been established in accordance with the NJPDES permit. There are no modifications to the nonradiological drain systems required for the extended power uprate, and biocide/chemical discharges will be consistent with existing permit limits. Extended power uprate will not introduce any new contaminants or pollutants and will not significantly increase the amount of any potential contaminants presently allowed for discharge by the NJDEP.

5.0 RADIOLOGICAL ENVIRONMENTAL IMPACTS

5.1 Radioactive Waste Streams

The radioactive waste systems at HCGS are designed to collect, process, and dispose of radioactive wastes in a controlled and safe manner. The design bases for these systems during normal operation are to limit discharges in accordance with 10 CFR 20 and satisfy the design objectives of Appendix I to 10 CFR 50. These limits and objectives will continue to be adhered to under the EPU.

In addition, operation at EPU conditions does not result in any changes in the operation or design of equipment in the radioactive solid waste, liquid waste, or gaseous waste management systems. The safety and reliability of these systems are unaffected by the power uprate. Neither the environmental monitoring of any of these waste streams, nor the radiological monitoring requirements of the HCGS Technical Specifications and/or Offsite Dose Calculation Manual, will be affected by the EPU. Furthermore, the EPU does not introduce any new or different radiological release pathways, nor does it increase the probability of either an operator error or an equipment malfunction, that would result in an uncontrolled radioactive release. The specific effects of the EPU on each of the radioactive waste management systems are evaluated below.

5.1.1 Solid Waste

The Solid Waste Management System (SWMS) collects and processes wet and dry radioactive wastes generated by the plant, packages and monitors the resultant solid radioactive product, and provides temporary storage facilities prior to offsite shipment and permanent disposal. The SWMS does not have any safety-related function. The SWMS is designed to package the wet and dry types of radioactive solid waste for offsite shipment and burial, in accordance with the requirements of applicable United States Nuclear Regulatory Commission (NRC) and Department of Transportation (DOT) regulations, including 10 CFR 61, 10 CFR 71 and 49 CFR 170 through 178. This results in radiation exposures to individuals and the general population well within the limits of 10 CFR 20 and 10 CFR 50. HCGS continually tracks the volume of solid radwaste generated, and reports annually to the Staff by generating Annual Radioactive Effluent Release

Reports (ARERRs) (Ref. 5-18). The annual low-level solid radwaste volumes generated at the HCGS are obtained from Reference 5-18 and shown in Table 5-1.

The post-EPU total solid radwaste increase from spent resin solids radwaste is due to the increased resin replacements from the reactor water cleanup system filter/demineralizer (RWCU F/D) and the condensate pre-filter demineralizers (Ref. 5-6, Section 3.3.2). The total solid radwaste consists of the spent resin, filter sludges, and evaporator bottoms. Average total solid radwaste shipped offsite for burial is 51.2 m^3 (Table 5-1). The increase in demineralizer/filter backwashes at EPU conditions will result in 14.7% increase in the solid radwaste (Ref. 5-6, Section 3.3.1.1), which will yield no more than an additional 7.53 m^3 of solid waste per year (51.2 $m^3 \times 0.147 = 7.53$ m^3). This would result in an increase of total waste generation rate from 51.2 m^3 to 58.8 m^3 (See Table 5-1 below).

The insignificantly small increase in total solid radwaste from the condensate demineralizer/filter backwashes will not result in waste volumes substantially above present level. Therefore, the offsite doses resulting from the post-EPU solid radwaste shipments and compliance with the DOT regulations, including 10 CFR 61, 10 CFR 71 and 49 CFR 170 through 178 requirements will not be impacted by the EPU. The additional solid waste volume due to EPU condition is well within the system design capacity of 945,944 lbs/year (Ref. 5-6, Section 3.3.2.2). In light of the HCGS ongoing efforts to reduce radioactive waste, which can be seen from Table 5-1 waste quantities, the waste reduction program will compensate for the insignificant increase in solid radwaste. The environmental impact of transportation of solid radwaste and spent fuel is discussed in Section 5.6.

Table 5-1
Annual Solid Waste Volume Shipped and Curie Content

Annual Radioactive Effluent Release Report (ARERR) No.	Annual Solid Radwaste Shipped To Burial Site	
	Volume (M^3) A	Activity (Ci) B
HCGS RERR-23 2000	36	141
HCGS RERR-24 2001	85	591
HCGS RERR-25 2002	90.4	533
HCGS RERR-26 2003	11.7	1.04
HCGS RERR-27 2004	33.1	420.5
Pre-Uprate Average	51.2	337.3
Post-EPU Average	58.8	386.9

A & B From Reference 5-18
Post-EPU Value = (1.147 × Average Volume or Activity)

5.1.2 Liquid Waste

The Liquid Waste Management System (LWMS) is designed to collect, store, process, and dispose of, or recycle, all radioactive or potentially radioactive liquid waste generated by plant operation or maintenance. The LWMS consists of three process subsystems, each for collecting, storing, processing, monitoring, and disposal of specific types of liquid wastes in accordance with their conductivity, chemical composition, and radioactivity. These systems are:

1. Equipment drain (high purity waste)
2. Floor drain (low purity waste)
    - Regenerant waste (high conductivity waste)
    - Chemical waste (decontamination solution waste and chemistry lab drains)
3. Detergent drain waste (laundry waste and personnel decontamination drains)

Sufficient treatment capability is available to process liquid waste to meet demineralized water quality requirements for plant reuse. Liquid wastes that are not processed to meet the quality requirement for reuse are released as excess water. Excess water is released in a controlled and monitored manner into the cooling tower blowdown line for dilution, and then discharged to the Delaware River. The LWMS has no safety-related function. The system is designed so that no potentially radioactive liquids can be discharged to the environment unless they have been processed, monitored, and diluted by mixing with the cooling tower blowdown release. This results in offsite radiation exposures within the limits of 10 CFR 20 and 10 CFR 50.

The increased frequency of RWCU F/D and Condensate Pre-Filter Demineralizer backwashes due to the EPU conditions will increase the total liquid radwaste volume (Ref. 5-6, Section 3.3.2). The RWCU F/D backwashes are expected to increase in proportion to the increase in reactor water iron concentration due to EPU (Ref. 5-6, Section 3.2.2.4). The condensate F/D backwashes are expected to increase in proportion to the increase in the condensate system flow due to EPU (Ref. 5-6, Section 3.2.2.6). Average historical total liquid radwaste prior to dilution is 1.898E+08 liters (Table 5-2). The total liquid radwaste volume increase as a result of the EPU is due to the increased frequency of RWCU F/D and Condensate Pre-Filter Demineralizer backwashes. The increase in liquid radwaste due to the EPU is estimated to be 2.2% (Ref. 5-6, Section 3.3.1.1), which will yield no more than an additional 4.173E+6 liters of liquid waste per year (1.897E+08 liters × 0.022 = 4.173E+06 liters). This would result in an increase of total liquid waste generation from 1.897E+08 liters to 1.94E+08 liters (See Table 5-2). The 2.2% increase is insignificant.

Table 5-2
Annual Liquid Waste Volume Prior To Dilution

Annual Radioactive Effluent Release Report (ARERR) No.	Annual Liquid Radwaste Prior To Dilution	
	Volume (Liter) A	Activity (Ci) B
HCGS RERR-23 2000	1.625E+08	2.333E-02
HCGS RERR-24 2001	1.970E+08	3.204E-02
HCGS RERR-25 2002	1.997E+08	2.630E-03
HCGS RERR-26 2003	2.072E+08	6.754E-02
HCGS RERR-27 2004	1.823E+08	3.233E-02
Pre-Uprate Average	1.897E+08	3.157E-02
Post-EPU Average	1.939E+08	3.226E-02

A & B From Reference 5-18
Post-EPU Value = (1.022 x Average Volume or Activity)
B = Total Fission & Activation Products Excluding Tritium

5.1.3 Gaseous Waste

The Gaseous Waste Management Systems (GWMS) include all systems that process potential sources of airborne releases of radioactive materials during normal operation and anticipated operational occurrences. Included are the off-gas system and various plant ventilation systems. These systems reduce radioactive gaseous releases from the plant by filtration or delay. Delay allows natural decay of radioisotopes prior to release. The function of the off-gas system is to collect and delay the release of non-condensable radioactive gases removed from the main condenser by the air ejectors during normal plant operation. Plant ventilation systems process airborne radioactive releases from other plant sources, such as equipment leakage, maintenance activities, the mechanical vacuum pump, and the steam seal system.

The continuous releases via the south plant vent are for the containment and auxiliary building exhaust, including the radwaste area and turbine building exhaust. The off-gas system releases are continuous via the north plant vent. The intermittent drywell purge releases and mechanical vacuum pump releases are via the south plant vent. The GWMS are designed to limit offsite doses from routine plant releases to significantly less than the limits specified in 10 CFR 20 and to operate within the dose objectives established in 10 CFR 50 Appendix I. Continuous monitoring is provided for pathways of airborne radioactive releases, with main control room annunciation prior to exceeding Technical Specification allowed limits. The off-gas system is designed to provide at least 35 days and 36 hours of delay time for xenon and krypton, respectively, at a 75 scfm airflow rate. The post-EPU radioactive release through the off-gas system is mainly a function of:

1. Radioactive Off-gas Release Rate;
2. Off-gas System Air Flow Rate; and,
3. Holdup Times In the Off-gas Charcoal Delay System.

5.1.3.1 Radioactive Off-gas Release Rate

The HCGS off-gas system normal noble gases release rates are based on sufficient fuel cladding defects to result in a total off-gas release rate of 100,000 μCi/sec after 30 minutes decay (Ref. 5-9, Table V). The isotopic noble gas release rates bound the resulting EPU noble gas release rates (Ref. 5-10, Appendix A, Class 1). Therefore, the normal radioactive release rate of noble gas is bounding for the EPU condition.

5.1.3.2 Off-gas System Air Flow Rate

The off-gas system air flow rate of 75 scfm is primarily a function of the condenser inleakage, which is independent of the power level (Ref. 5-12, Section 3.2.2.2). The condenser inleakage is primarily a function of material condition, which is not affected by the EPU condition. Therefore, the existing off-gas flow rate of 75 scfm remains bounding for the EPU condition.

5.1.3.3 Holdup Times in Off-gas Charcoal Delay System

The holdup time required for noble gas in the charcoal adsorbers can be determined by the decontamination factor described as follows (Ref. 5-13, Section 4.10):

$$T = (K_d \times M) / F$$

Where:

T = average delay time, sec

K_d = dynamic adsorption coefficient, cm^3/g

M = mass of absorbent, g

F = flow rate of noble gas, cm^3/sec

All values are those at operating conditions.

Dynamic adsorption coefficients for xenon and krypton are based on the charcoal type, relative humidity, temperature, pressure, and other effects (Ref. 5-13, Section 4.10). The factors affecting a dynamic adsorption coefficient are not expected to change during the EPU when the recombiner temperature is at or below the bounding 693^0F value. Therefore, the off-gas charcoal delay system holdup time remains bounding for the EPU.

The reactor coolant source terms have been determined to remain bounding for the EPU condition (Ref. 10, Appendix A). The plant ventilation systems radionuclide concentrations are based on the reactor coolant system source terms. Consequently, the potential airborne activities resulting from the reactor coolant system leakages remain bounding for the EPU condition. Therefore, the gaseous effluent releases and resulting offsite doses from the ventilation systems, which process and control the potential airborne sources of radioactive materials, will not be impacted by the EPU condition.

The radioactive release rate of the gaseous effluent is administratively controlled by the HCGS Offsite Dose Calculation Manual (ODCM) (Ref. 5-14, Control 3/4.11.2 and Appendices C & D). The annual gaseous effluent releases are assessed in the ARERR (Ref. 5-18) using the actual measured or sampled isotopic activities listed in Table 5-3. Table 5-3 show that the 5-year average total annual noble gases and iodine (I-131), and particulate activities are less than the

FES annual average values. Although, the annual particulate activity release in year 2000 was larger than the FES value, per Tables 5-7 through 5-10, the resulting offsite doses from this release for year 2000 were considerably less than the allowable dose limits of 10 CFR 20 and 10 CFR 50, Appendix I.

Table 5-3
Annual Gaseous Effluent Activity Released To Environment

Annual Radioactive Effluent Release Report (ARERR) No.	Annual Gaseous Effluent Activity Release		
	Noble Gases (Ci) A	Iodine (Ci) B	Particulate (Ci) C
HCGS RERR-23 2000	2.990E+01	1.914E-04	5.910E-02
HCGS RERR-24 2001	7.518E-04	2.848E-03	5.853E-04
HCGS RERR-25 2002	4.312E+00	3.438E-03	2.177E-04
HCGS RERR-26 2003	6.300E+01	1.348E-02	2.655E-05
HCGS RERR-27 2004	9.251E+00	5.840E-03	6.768E-05
Pre-Uprate Average	2.129E+01	5.160E-03	1.200E-02
HCGS FES Value	7.329E+03	2.500E-01	4.184E-02

A, B & C From Reference 5-18
HCGS FES Value From Reference 5-5, Table D-1

5.2. Normal In-Plant and Annual Occupational Exposures and Offsite Doses

5.2.1 Normal Operation In-Plant Radiation

During reactor operation, the coolant passing through the core region becomes radioactive as a result of nuclear reactions. Coolant activation products, primarily Nitrogen-16, are the dominant source of gamma radiation fields in the turbine building. Because these sources are produced by activation of coolant in the core region, their rates of production are proportional to power. However, while the magnitude of the source production increases in proportion to power, the concentration in the steam remains nearly constant. This is because the increase in activation production is balanced by the increase in steam flow. Nevertheless, the radiation field resulting from activation products will increase with the EPU primarily due to the increased steam flow and the resultant decrease in transit time for the activation products as they flow from the reactor pressure vessel to the turbine complex. Since these activation products typically have extremely short half-lives, on the order of seconds, the decrease in transit time will result in a measurable increase in radiation exposures in various steam components. The HCGS has implemented a Hydrogen Water Chemistry (HWC) program with a hydrogen injection rate of 35 scfm, which increased the main steam system and subsystem N-16 concentration by a factor of 4.3 over pre-HWC N-16 concentration.

The N-16 concentration of 50 μCi/g at the Reactor Pressure Vessel (RPV) nozzle remains bounding for the EPU because the increase in the N-16 production rate is balanced by the increase in the steam flow. The N-16 transit time of interest is the first 10 seconds, because during this period the main steam has already traveled through the major steam components including the steam headers, high pressure (HP) turbine inlet and outlet piping, cross-over and cross-under piping, moisture separators, and feedwater heaters, which contribute to the major in-plant (direct dose) and skyshine dose. An analysis of post-EPU N-16 transit times in various steam components indicates that the increase in N-16 source strength is approximately 16% for a 20% increase in steam flow (Ref. 5-15, Section 8.0).

A post-EPU radiation exposure assessment in the turbine complex is performed in Reference 5-15 (Tables 3A and 3B) using the likelihood of radiological conditions based on operational data obtained during the implementation of the HWC with a hydrogen injection rate of 35 scfm. Due

to conservatisms in the original design, higher-than-expected radiation source terms, and analytical techniques employed for the design of plant shielding to maintain the plant exposure As Low AS Reasonably Achievable (ALARA), the increase in post-EPU radiation levels does not affect the existing radiation zoning or shielding in the various areas of the plant.

5.2.2 Annual Occupational Exposure – Person-Rem

The EPU impact on the annual plant radiation exposure (Person-Rem) is assessed in Reference 5-15, Table 7 with the post-HWC exposure. The EPU related increase is insignificant. Although the implementation of HWC with a hydrogen injection rate of 35 scfm has substantially increased the N-16 contribution to in-plant and skyshine radiation exposures, the average annual radiation exposure measured during with the HWC implemented was substantially lower than the previous average annual exposures as shown Table 5-4, primarily due to strict adherence to good ALARA practices, conservatively designed shielding, and administrative controls. EPU will increase the in-plant occupational exposure by 16%. In addition, the downward trend in occupational exposures at HCGS is expected to continue (Table 5-8) due to the effectiveness of the ALARA Program. The NRC used the collective occupational exposure of 920 person-rem (Ref. 5-5, Appendix D, Table D-8) in the HCGS FES to assess the risks to nuclear-power-plant workers, which is substantially higher than the projected post-EPU occupational exposure of 146 person-rem (Table 5-4). Therefore, the NRC assessment of potential health risk to the exposed work-force at the Hope Creek facility based on the 920 person-rem is bounding for the EPU condition (Ref. 5-5, Section 5.9.3.1.1).

Table 5-4 INPO Occupational Exposure Data for Hope Creek Site	
Actual Occupational Exposure Data - Person-Rem	
Year	**Hope Creek**
	A
1990	209.2
1991	366.9
1992	437.2
1993	97.6
1994	342.5
1995	199.2
1996	171.7
1997	351.8
1998	56.3
1999	281.5
2000	***199.3***
2001	***154.7***
2002	***22.5***
Total Person-Rem	**2890.4**
Pre-EPU Average Person-Rem During HWC Years 2000 to 2002	**126**
Post-EPU Person-Rem	**146**
HCGS FES Person-Rem	**920**
A From Reference 5-15, Table 8	
HCGS FES Person-Rem From Reference 5-5, Table D-8	

5.2.3 Post-EPU Offsite Doses

5.2.3.1 Compliance with 10 CFR 20.1302(a) Requirement

The accessibility to the Station perimeter for members of the public (MOP) changed on September 11, 2001. The definition of members of the public now includes the members of the New Jersey National Guard, which augment the security force at the site. Their typical patrol spans the site. In accordance with the requirements of ODCM 6.9.1.8 (SGS) and 6.9.1.7 (HCGS), the dose to the public inside the site boundary has been calculated based on the assumption that the National Guard works a 40 hour week, therefore, all doses are conservatively multiplied by 0.25 to assess their dose. For the 12-month reporting period the calculated dose is 2.29E-01 mrem total body (Ref. 5-18.a, page 14). The combined post-EPU total body dose to the MOP is 1.43 mrem/year [(0.229 mrem/year + 1.0 mrem/year due to the effluent releases) x 1.16 (projected increased exposure due to EPU)], which is substantially less than the allowable limit of 100 mrem/year.

5.2.3.2 Compliance with 10 CFR 20.1302(b)(ii) Requirement

The site boundary locations were reviewed on the basis of continuous occupancy. The south and west site boundaries are adjacent to the Delaware River, where personnel occupancy will be very low. Therefore, only north and east site boundaries are considered for continuous occupancy at an unrestricted area. The dose survey results indicate that the dose rate at the east site boundary is higher than at the north site boundary. Therefore, the annual dose to the MOP continuously present at the east site boundary is calculated in Reference 5-15, Section 6.3 to be 9.3 mrem/year due to EPU. As shown in Table 5-5, this annual dose is much less than the allowable limit of 50 mrem/year.

5.2.3.3 Compliance with 40 CFR 190.10(a) Requirement

To assess compliance with 40 CFR 190.10(a), direct radiation exposures from the following principal sources are considered:

1. The activity stored outside the plant structures in the condensate storage tank (CST);

2. Turbine shine due to the Nitrogen-16 present in the reactor steam; and,
3. Radiation shine during transport of drummed radwaste and spent fuel assemblies to offsite facilities.

The dose contributions from the CST, the radwaste transport casks, and the spent fuel shipping casks at the site boundaries are considered negligible when compared to the post-EPU N-16 shine from the turbine building. The N-16 present in the reactor steam in the primary steam lines, HP turbine inlet and exhaust headers, cross-over and cross-under piping, and moisture separators provides a major dose contribution to locations outside the plant enclosure as a result of the high energy gamma rays that are emitted as the N-16 decays. The maximum dose rate for areas with potentially high occupancy occurs at the east site boundary. Therefore, the assessment for this limit applicable to unrestricted areas is bounded by the assessment in the preceding Section 5.2.3.2 (i.e., the annual dose to the MOP continuously present at the site boundary is expected to be 9.3 mrem/year due to EPU). Per Table 5-5, this annual dose is much less than the allowable limit of 25 mrem/year. The N-16 only contributes to the whole body dose. The inhaled dose from the gaseous effluent and direct dose from the liquid effluent are included in the annual site boundary dose.

The EPU creates neither new nor different sources of offsite dose from HCGS operation nor does the EPU significantly increase present offsite radiation levels. Therefore, the post-EPU offsite doses shown in Table 5-5 will remain within a fraction of the regulatory limits.

Table 5-5 Annual Post-EPU Offsite Doses		
Regulatory Compliance Required	Post-EPU Dose To MOP (mrem/yr)	Regulatory Allowable Limit (mrem/yr)
20 CFR 20.1301/1302(a)	1.43	100
20 CFR 20.1302(b)(ii)	9.3	50
49 CFR 190, Subpart B	9.3	25

5.2.3.4 Compliance with 10 CFR 50, Appendix I Requirement

Liquid effluents are monitored in accordance with Table 4.11.1.1.1-1 of the HCGS ODCM (Ref. 5-14). The estimated doses for the current licensed power level in Table 5-6 represent the maximum total body and organ radiation doses that could be received by a member of the general public, which are small fractions of allowable limits. The doses were calculated using methods described in Regulatory Guide 1.109 and represent calculations for the 12 month reporting interval. The increase in the general public and population doses due to the post-EPU liquid effluent releases is 2.2% (Ref. 5-6, Section 3.3.1.1), which is insignificant and results in a negligible increase in the post-EPU total doses. Therefore, the existing doses due to the liquid effluents are considered bounding for the EPU condition.

The gaseous effluents are monitored in accordance with Table 4.11.2.1.2-1 of the HCGS ODCM. The estimated doses for the current licensed power level listed in Tables 5-7 and 5-8 represent the maximum gamma and beta radiation doses that could be received by a member of the general public. These doses are small fractions of the allowable limits. The gaseous effluent releases are not impacted by the EPU (Ref. 5-8, Section 7.2). Therefore, the existing general public and population doses from the gaseous effluents remain bounding for the EPU.

Radiation doses to members of the public from the proposed EPU operation have been examined from a variety of perspectives and the impacts were found to be well within design objectives and regulations (Tables 5-9 and 5-10). Both maximum individual and average doses are expected to remain within regulatory limits during the continued EPU operation.

Table 5-6
Annual Total Body & Organ Doses From Liquid Effluent Release

Dose Category	Annual Dose (mrem) Liquid Effluent Release			Annual Maximum Dose			Annual Dose Limit (mrem) F	Percent of Allowable Limit G=(E/F)*100
	2000 A	2001 B	2002 C	Pre-EPU (mrem) D	Post-EPU (mrem) E=Dx1.017	HCGS FES (mrem) F1		
Total Body	2.73E-03	5.26E-05	2.68E-03	2.73E-03	2.78E-03	< 0.1	3	0.093
Any Organ	1.33E-02	4.24E-04	9.35E-03	1.33E-02	1.35E-02	1.40E-01	10	0.135
D = Max of A, B, & C								
A, B, & C From Reference 5-18								
F1 From Reference 5-5, Appendix D, Table D-7								

Table 5-7
Annual Air Gamma Dose From Gaseous Effluent Release

Year	Cumulative Air Gamma Dose Per Quarter Gaseous Effluent Release				Annual Air Gamma Dose Gaseous Effluent Release				Percent of Allowable Limit
	1st Quarter (mrad) A	2nd Quarter (mrad) B	3rd Quarter (mrad) C	4th Quarter (mrad) D	Pre-EPU Dose (mrad) E=A+B+C+D	Post-EPU Dose (mrad) F=E	HCGS FES (mrad) F1	Dose Limit (mrad) G	H=(F/G)*100
2000	1.56E-02	2.30E-04	2.18E-03	2.36E-03	2.04E-02	2.04E-02	4.70E+00	10.0	0.204
2001	0.00E+00	2.04E-08	0.00E+00	1.18E-08	3.22E-08	3.22E-08		10.0	0.000
2002	0.00E+00	1.97E-04	5.65E-05	0.00E+00	2.54E-04	2.54E-04		10.0	0.003
A, B, C, & D From Reference 5-18									
F1 From Reference 5-5, Appendix D, Table D-7									

Table 5-8 Hope Creek Annual Air Beta Dose From Gaseous Effluent Release									
Year	Cumulative Air Beta Dose Per Quarter Gaseous Effluent Release				Annual Airborne Beta Dose Gaseous Effluent Release				Percent of Allowable Limit
	1st Quarter (mrad) A	2nd Quarter (mrad) B	3rd Quarter (mrad) C	4th Quarter (mrad) D	Pre-EPU Dose (mrad) E=A+B+C+D	Post-EPU Dose (mrad) F=E	HCGS FES (mrad) F1	Dose Limit (mrad) G	H=(F/G)*100
2000	1.64E-02	2.41E-04	2.29E-03	2.47E-03	2.14E-02	2.14E-02	6.90E+00	20.0	0.107
2001	0.00E+00	6.05E-08	0.00E+00	1.52E-08	7.57E-08	7.57E-08		20.0	0.000
2002	0.00E+00	4.17E-04	7.59E-05	0.00E+00	4.93E-04	4.93E-04		20.0	0.002
A, B, C, & D From Reference 5-18									
F1 From Reference 5-5, Appendix D, Table D-7									

Table 5-9 Annual Total Body & Population Doses at Site Boundary Gaseous Effluent Pathways - 10 CFR 20			
Dose Type	**Year**	**Annual Total Body Dose (mrem)**	**Allowable Regulatory Limit (mrem)**
Total Body Dose	2002	2.29E-04	500.00
	2001	2.82E-08	
	2000	1.95E-02	
Average Total Body Dose		**6.58E-03**	
Post-EPU Total Body Dose		**6.58E-03**	
Total Population Dose	2002	3.90E-01	N/A
	2001	1.32E+00	
	2000	1.41E+00	
Average Total Population Dose (person-rem)		**1.04E+00**	
Post-EPU Total Population Dose (person-rem)		**1.06E+00**	
Average Population Dose	2002	8.66E-05	N/A
	2001	2.22E-06	
	2000	2.36E-04	
Average Ave Population Dose		**1.08E-04**	
Post-EPU Avg Population Dose		**1.10E-04**	
Dose Information From Reference 5-18			

Table 5-10 Annual Thyroid Dose at Unrestricted Area Gaseous Effluent Pathways - 10 CFR 50, Appendix I Compliance				
Dose Type	Year	Annual Organ Dose Pre-EPU (mrem)	HCGS FES* (mrem)	Allowable Regulatory Limit (mrem)
Organ Dose (Thyroid)	2002	3.60E-02	3.10E+00	15
	2001	3.16E-02		
	2000	4.27E-03		
Average Organ Dose (Thyroid)		2.40E-02		
Post-EPU Organ Dose (Thyroid)		2.40E-02		
Pre-EPU Organ Dose Information From Reference 5-18				
* Annual Organ Dose From Reference 5-5, Appendix D, Table D-7				

5.3 Radiological Consequences of Accidents

To demonstrate that certain features important to the safety of the HCGS meet acceptable design and performance criteria, both PSEG and the Staff have analyzed the potential consequences of a number of postulated accidents. Section 5.9.4.5(1) of the HCGS Final Environmental Statement (FES) (Ref. 5-5) indicates that in the HCGS safety analysis and evaluation, three classes of postulated accidents have been considered based on probability of occurrence. These classes are (1) incidents of moderate frequency (events that can be reasonably be expected to occur during any year of operation), (2) infrequent incidents (events that might occur once during the life time of the plant), and (3) limiting faults (accidents not expected to occur, but that have potential for significant releases of radioactivity). The following subsections address the impact of the EPU on the assumptions and conclusions for these accident classes.

5.3.1 Class 1 – Incidents of Moderate Frequency

Incidents of moderate frequency are analyzed to ensure that they will not cause damage to either the fuel or the reactor coolant pressure boundary, and to ensure that the radiological dose is maintained within 10 CFR 20 guidelines (Ref. 5-19, page 15-1). Anticipated operational occurrences are those transients resulting from single equipment failures or single operator errors that might be expected to occur during normal or planned modes of plant operation. The acceptance criteria for these incidents require that the reactor core and associated control, instrumentation, and protection systems be designed with appropriate margin to ensure that acceptable fuel design limits and that the design condition of reactor coolant pressure boundary are not exceeded during normal operation including anticipated operational occurrences. The FES concludes that the radiological consequences of moderate frequency incidents are similar to the consequences from normal operation effluent releases previously discussed in Section 5.1.2. Because of improved fuel integrity and the increased effectiveness of the gaseous and liquid treatment systems, the post-EPU radiological consequences will be considerably less than that predicted by the FES and will remain within the allowable regulatory limits (See Tables 5-3, 5-4, 5-5, & 5-7 for comparison of the post-EPU doses with FES doses).

5.3.2 Class 2 – Infrequent Incidents

Class 2 events are those events that might occur once during the life of the plant. The EPU does not increase the probability of a fuel handling accident (FHA). The following section discusses the FHA.

The HCGS operating license (OL) was amended by the Staff on October 3, 2001 (Ref. 5-22), to adopt the Alternative Source Term (AST) for HCGS design basis analyses. The OL was subsequently amended to modify the secondary containment integrity during a refueling outage and to remove the filtration, recirculation, and ventilation system (FRVS) recirculation subsystem charcoal filters from the Technical Specifications (Ref. 5-23). The FHA was re-analyzed using the AST and EPU core inventory.

The post-FHA EAB and Low Population Zone (LPZ) doses in Table 5-11 are within the allowable limits, which demonstrate that removal of the charcoal from the FRVS recirculation

filters does not adversely impact the dose mitigation system compliance with the acceptable design objectives. Although, the resulting environmental impact following a FHA is higher than that predicted in the HCGS FES due to the plant modifications implemented after the FES was issued, the environmental impact will remain within the allowable limits for the FHA incident. The environmental impact is not expected to differ significantly for EPU operation because it is analyzed in a fashion consistent with the regulatory limit set for the incident.

Table 5-11
Post-FHA EAB, LPZ, & CR Doses

	Fuel Handling Accident Occurring in Reactor TEDE Dose (rem) Receptor Location		
	Control Room	**EAB**	**LPZ**
Calculated Dose*	3.31E+00	5.27E-01	5.27E-02
Allowable TEDE Limit	5.00E+00	6.30E+00	6.30E+00

*From Reference 5-24, Section 7.0

5.3.3 Class 3 – Limiting Faults

Class 3 limiting fault accidents are those events that are not expected to occur, but have the potential for significant releases of radioactivity. The HCGS FES evaluated the loss of coolant accident (LOCA) as a Class 3 accident (Ref. 5-5, Section 5.9.4.5 and Table 5-13). In addition to the LOCA, the results of other limiting fault accidents – control rod drop accident (CRDA) and main steam line break accident (MSLBA) – are provided in the following subsections to cover the entire spectrum of limiting faults. However, the resulting post-EPU radiological consequences will be higher than that predicted by the FES (Ref. 5-5, Table 13) due to various plant modifications and TEDE dose criteria implemented after the FES was issued, they will remain within the allowable regulatory limits (See Tables 5-12, 5-13, 5-14, & 5-15 for comparison of the post-EPU doses with allowable limits).

5.3.3.1 Loss of Coolant Accident (LOCA)

The post-LOCA EAB, LPZ, and CR doses are analyzed using the guidance in Regulatory Guide 1.183, Appendix A (Ref. 5-25) with removal of Main Steam Isolation Valve Sealing System

(MSIVSS), charcoal from the FRVS recirculation filters, increase of total MSIV leakage from 46 scfh to 250 scfh, EPU core inventory, and TEDE dose criteria in Table 6 of Reference 5-25. The results are summarized in Table 5-12.

Table 5-12
Post-LOCA EAB, LPZ, and CR Doses

Post-LOCA Activity Release Path	Post-LOCA TEDE Dose (Rem) Receptor Location Control Room	EAB	LPZ
Containment Leakage	1.05E+00	3.73E-01	1.62E-01
ESF Leakage	1.25E+00	1.91E-01	9.79E-02
MSIV Leakage	2.13E+00	2.63E+00	4.56E-01
CR Filter Shine	2.46E-03	0.00E+00	0.00E+00
Total	**4.43E+00**	**3.19E+00**	**7.16E-01**
Allowable TEDE Limit	**5.00E+00**	**2.50E+01**	**2.50E+01**

5.3.3.2 Control Rod Drop Accident (CRDA)

The post-CRDA EAB, LPZ, and CR doses are analyzed using the guidance in Regulatory Guide 1.183, Appendix C (Ref. 5-25), EPU core inventory, and TEDE dose criteria in Table 6 of Reference 5-25. The results are summarized in Table 5-13.

Table 5-13
Post-Control Rod Drop Accident EAB, LPZ, and CR Doses

	Control Rod Drop Accident TEDE Dose (Rem) Receptor Location Control Room	EAB	LPZ
Calculated Dose*	1.37E-01	2.92E-02	6.23E-03
Allowable TEDE Limit	**5.00 E+00**	**6.30E+00**	**6.30E+00**

* From Reference 5-27, Section 7.0

5.3.3.3 Main Steam Line Break Accident (MSLBA)

The post-MSLBA EAB, LPZ, and CR doses are analyzed using the guidance in Regulatory Guide 1.183, Appendix D (Ref. 5-25), EPU core inventory, and TEDE dose criteria in Table 6 of Reference 5-25 with a pre-accident iodine spike (4.0 μCi/g DE I-131) and the maximum equilibrium iodine concentration (0.2 μCi/g DE I-131). The results are summarized in Tables 5-14 and 5-15.

Table 5-14
Post-MSLB Accident EAB, LPZ, CR Doses with Pre-accident Iodine Spike

	Main Steam Line Break Accident with Pre-accident Iodine Spike TEDE Dose (rem)		
	Receptor Location		
	Control Room	EAB	LPZ
Calculated Dose*	3.60E+00	9.42E-01	9.45E-02
Allowable TEDE Limit	**5.00E+00**	**2.50E+01**	**2.50E+01**

* From Reference 5-28, Section 7.1

Table 5-15
Post-MSLB Accident EAB, LPZ, CR Doses
with Maximum Equilibrium Iodine Concentration

	Main Steam Line Break Accident with Maximum Equilibrium Iodine Concentration for Continued Full Power Operation TEDE Dose (rem)		
	Receptor Location		
	Control Room	EAB	LPZ
Calculated Dose*	1.81E-01	5.61E-02	5.63E-03
Allowable TEDE Limit	**5.00E+00**	**2.50E+00**	**2.50E+00**

* From Reference 5-28, Section 7.2

5.4 Severe Accidents

The severe accidents, frequently called Class 9 accidents, are considered less likely to occur than DBA, but their consequences could be more severe for both the plant itself and for the environment. PSEG analyzed the severe accident in Reference 5-30 (Section 7.1 and Appendix C) and concluded that some of the environmental impacts could be severe, but the likelihood of their occurrence, and hence, the public risk, were judged to be small. The NRC independently analyzed the Class 9 accidents in Reference 5-5, Section 5.9.4.5(2). The NRC concluded in the HCGS FES that the severe accident risks from HCGS are expected to be a small fraction of the risks the general public incurs from other natural sources. Further, the best estimate calculations show that the risks of potential reactor accidents at HCGS are within the range of such risks from other power plants. Based on the analyses of environmental impact of Class 9 accidents, the NRC concluded that there were no special or unique circumstances about the HCGS site and environs that would warrant consideration of alternatives for HCGS (Ref. 5-5, Section 5.9.4.6). The post-EPU severe accident risks to the general public are still expected to be a small fraction of the risks incurred from natural background sources and are bounded by the FES analyses.

5.5 Environmental Effects Of Uranium Fuel Cycle Activities (Summary Table S-3)

Summary Table S-3 of 10 CFR 51.51 was adopted for the HCGS licensing process, and used by the Staff to assess the environmental impacts from the uranium fuel cycle as related to the operation of HCGS in Reference 5-5, Appendix C. The radiological environmental impact of the uranium fuel cycle for the EPU operation has been reviewed and assessed (Ref. 5-31). The assessment of health effects was based on the values presented in Summary Table S-3, regulatory standards including 10 CFR 20, 10 CFR 61, 10 CFR 71 and 49 CFR 170 through 178, the gaseous and liquid releases from uranium mining, milling and active tailings, and radon-222 and technetium-99 releases from the un-reclaimed open-pit mines and stabilized tailings piles, to support the post-EPU operation of HCGS (Ref. 5-31). Based on the evaluation, it is concluded that the radiological environmental impact of HCGS EPU operation on the U.S. population from radioactive gaseous and liquid releases (including Rn-222 and Tc-99) resulting from the uranium fuel cycle is very small when compared with the impact of natural background radiation. Therefore, the HCGS post-EPU operation is bounded by the radiological

environmental assessment of Table S-3.

5.6 Environmental Impact of Transportation of Fuel and Waste (Summary Table S-4)

Summary Table S-4 of 10 CFR 51.52 was adopted for the HCGS licensing process and used by the Staff to assess the environmental impacts from the transportation of fuel and waste as related to the operation of HCGS in Reference 5-5, Section 5.9.3.1.2. The radiological and non-radiological environmental impacts of transportation of fuel and waste due to the EPU operation have been reviewed and assessed in Reference 5-31. Per the assessment, the following conditions in paragraph (a) of 10 CFR 51.52 will not be met during the EPU operation, however, they are acceptable as explained in the following sections:

Table 5-16		
Plant Parameter	**10 CFR 51.52(a) Criteria**	**EPU Parameter Value**
Reactor Core Thermal Power Level	3,800 MW_t	3,952 MW_t[1]
Uranium-235 Enrichment Percent	$\leq 4\%$	$\leq 4.6\%$[2]
Average Level of Irradiation	33,000 MWD/MTU	$\leq$ 35,000 MWD/MTU[2]
1. From Reference 5-7, Section 1.1, Project Summary		
2. From Reference 5-7, Section 1.3, Results Summary		

5.6.1 Reactor Thermal Power Level

The WASH-1238 environmental impact analysis for the transportation of spent fuel and radwaste is based on shipments of fresh fuel, irradiated fuel, and solid radioactive waste from a boiling water or pressurized water reactor with design ratings in the range of 3,000 to 5,000 MWt or 1,000 to 1,500 MWe (Ref. 5-29, page 3). This range bounds the EPU power level of 3,952 MWt. The radiation exposure to transportation workers and the MOP are calculated in Appendix D of WASH-1238 based on the regulatory limit of 10 mrem/hr at 6 feet from the surface of the vehicle (Ref. 5-29, page 107), which is independent of power level. Although the increase in the transportation exposure due to the EPU is negligible, adherence to the

regulatory dose rate limit during the transportation of post-EPU spent fuel and solid radioactive waste will result in the transport workers and MOP radiation exposures in compliance with the exposure values in Summary Table S-4.

5.6.2 U-235 Enrichment and Fuel Burnup

The data presented in Summary Tables S-3 and S-4 are, in part, based on an average burnup assumption of 33,000 MWD/MTU and a Uranium-235 enrichment assumption of 4 wt.%. Under extended power uprate conditions, fuel consumption is expected to increase such that the batch average burnup of the fuel assemblies will be in excess of 33,000 MWD/MTU but less than 60,000 MWD/MTU. To support extended burnup, the U-235 enrichments levels will also increase to greater than 4 wt.% but less than 5 wt.%. The NRC has previously evaluated the impact of increased burnup to 60,000 MWD/MTU with U-235 fuel enrichment to 5 wt.% on the conclusions of Summary Table S-4 (Ref. 5-11). Although some radionuclide inventory levels and activity levels are projected to increase, the NRC noted that little or no increase in the amount of radionuclides released to the environment during normal operation was expected. The NRC determined that the incremental environmental effects of increased enrichment and burnup on transportation of fuel, spent fuel, and waste were not significant. In addition, the NRC recognized the salient environmental benefits of extended burnup such as reduced occupational dose, reduced public dose, reduced fuel requirements per unit electricity, and reduced shipments. The NRC concluded that the environmental impacts described by Summary Table S-4 were bounding and were also applicable for burnup levels to 60,000 MWD/MTU and U-235 enrichment levels up to 5 wt.%. Therefore, the environmental impacts described by Summary Table S-4 are bounding for the HCGS EPU operations.

5.6.3 Non-radiological Impact of Transportation of Fuel and Waste

The non-radiological environmental impacts associated with the transportation of spent fuel and radioactive waste include the heat per irradiated fuel cask in transit, weight, traffic density, fatal and non-fatal injuries, and property damage.

The weight of shipment by truck must meet State restrictions on gross weight of the vehicle, which ensure against damage to bridges or highways. The limited number of shipments per reactor year is too small to have any measurable effect on the environment due to the resultant increase in traffic density. The weights of rail and barge shipments are too small to result in any measurable effects on the environment.

The effect of a heat output of 250,000 Btu/hr from an irradiated fuel cask in transit in Summary Table S-4 is based on an actual design of a shipping cask for LWR fuel (Ref. 5-21, page 2). At the time of discharge from the reactor, the radioactivity and the decay heat of high burnup fuel may be higher, but this heat output increase diminishes as the cooling time is lengthened. Since the spent fuel is cooled more than a year before it is shipped to a burial site, the shipping cask heat dissipation rate would be substantially lower than 250,000 Btu/hr. With the existing inventory of spent fuel that has accumulated, the age of any spent fuel that is reprocessed or transported to a repository is likely to be many years. At the conclusion of the hearings on reprocessing and waste management (Dockets 50-277, 50-278, 50-320, 50-354, and 50-355, Consolidated Hearing on Radon Before the Appeal Board), the Hearing Board concluded that 5 years would be a reasonable value to use in making estimates (Ref. 5-20, Section 6.2.3, pages 310 & 311). The scenario that is visualized today for emplacement of spent fuel and high-level waste in a geologic repository calls for this final disposal to occur after the spent fuel or waste is at least 10 or more years old. Longer cooling times on site reduce the impact on the environment and increase the margin of safety once the fuel is being transported.

5.7 Emergency Planning Impacts

The emergency preparedness plan at the HCGS is established for an accident including the protective action measures for the public to ensure that the condition of on- and off-site emergency preparedness provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. In the event of a release of radioactive material from the plant, protective actions can be taken to move or shelter members of the public in the projected path of the material. The success of these actions in preventing exposure of members of the public to released radioactive material is dependent upon the warning time available prior to the release and the time it takes to carry out the protective

actions. In general, this latter item (the time to carry out the protective action) is mostly influenced by the size of the population around the plant. Other measures include provisions for dissemination to the public of basic emergency planning information; provisions for rapid notification of the public during a serious reactor emergency; and methods, systems, and equipment for assessing and monitoring actual or potential off-site consequences in the event of a radiological emergency condition. These protective measures and various emergency levels are independent of the licensed power level. Therefore, the post-EPU operation of HCGS will not impact the existing emergency preparedness plan adversely.

5.8 Environmental Effects of Decommissioning

HCGS has developed a Decommissioning Cost Analysis (DCA) (Ref. 5-32) to present the cost to promptly decommission HCGS following a scheduled cessation of plant operations. Additional costs of decommissioning are only associated with the increased activity levels in the plant and the increase in fuel activity. Effects on the DCA related to the EPU are negligible.

The HCGS Decommissioning Cost Analysis (DCA) (Ref. 5-32) was developed analyzing the DECON alternative. The DECON alternative is defined as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations." (Ref. 5-33) Decommissioning costs are analyzed considering the preparation period, the actual decommissioning operations, and the site restoration.

The preparation period is undertaken to ensure a smooth transition from plant operations to decommissioning. This period includes planning, permitting, submittal of the license termination plan, determination of staff requirements, characterization of the site, and development of the post-shutdown decommissioning activities report (PSDAR). The EPU will have no impact on the costs determined for the preparation period in the DCA.

The decommissioning operations period includes the dismantling, decontamination, and disposal of components and equipment. The increased radiation and activity levels associated

with the EPU will slightly increase the costs of disposal of radioactive materials. Any increase in cost attributable to the EPU would be negligible because the calculated increase in plant solid waste and resin activity is less than 0.5% (see Section 5.1) and the total cost for radwaste disposal during this phase is only 16% of the estimated cost.

The site restoration period includes the demolition and removal of site structures and facilities and extensive radiological surveys. The EPU will have no effect on the estimated costs of the site restoration phase.

The spent fuel management costs, prior to disposal, are included in the DCA. These costs are approximately 7.24% of the total cost in the DCA. Therefore, the costs associated with spent fuel management after cessation of operations related to the EPU will be negligible.

The cost to dispose of spent fuel generated from plant operations is not included in the DCA. Ultimate disposal of spent fuel is within the province of the Department of Energy's (DOE's) Waste Management System. As such, the disposal cost is financed by a kilowatt-hour surcharge paid into the DOE's waste fund during operations. Any increase in the costs of spent fuel disposal related to the EPU will be accommodated in the surcharge during plant operations.

Therefore, the costs of decommissioning will not be substantively affected by the EPU.

5.9 Section 5 References

5-1. 10 CFR 51.51, Uranium Fuel Cycle Environmental Data – Table S-3

5-2. 10 CFR 51.52, Environmental Effects of Transportation of Fuel and Waste – Table S-4

5-3. HCGS to USNRC Letter LR-N00-0405, Request for License Amendment, Increased Licensed Power Level, LCR H00-05, December 1, 2000

5-4. NRC Letter, Subject: Hope Creek Generating Station – Environmental Assessment and Finding of No Significant Impact for Increase in Allowable Thermal Power Level (TAC No. MB0644), June 18, 2001

5-5. NUREG-1074, Final Environmental Statement Related to the Operation of Hope Creek Generating Station, Docket No. 50-354, December 1984

5-6. GE-NE-0000-0000-0152-01, Revision 1, Project Task Report T0800, Liquid and Solid Radwaste Management, April 2004

5-7. GE-NE-0000-0015-01114-R3, DRF 0000-0004-6923, Revision 3, Project Task Report T0802, Radioactive Source Term – Core Inventory, April 2004

5-8. HCGS Calculation No. H-1-ZZ-MDC-1955, Revision 0IR0, Radiological Impact Evaluation of EPU on Radwaste Management

5-9. GE Report No. 22A2703F, Revision 3, "Radiation Sources", (VTD PNO-A61-4100-0047, Sheet 1, Revision 2)

5-10. GE-NE-0000-0011-3853-R3, DRF 0000-0004-6923, Revision 3, Project Task Report T0807, Coolant Radiation Sources, April 2004

5-11. NUREG/CR-5009 (PNL-6258), Assessment of the Use of Extended Burnup Fuel in Light Water Power Reactors, February 1988

5-12. GE-NE-0000-0005-7177-01, Revision 1, Project Task Report T0801, Gaseous Waste Management, April 2004

5-13. ANSI/ANS-55.4-1993, Gaseous Radioactive Waste Processing Systems For Light Water Reactor Plants

5-14. HCGS Offsite Dose Calculation Manual, Revision 20

5-15. HCGS Calculation No. H-1-ZZ-MDC-1930, Revision 0IR1, EPU Impact on N-16 Radiation Exposure to Various Areas of Plant and Member of Public

5-16. HCGS Calculation No. H-1-ZZ-MDC-1956, Revision 0IR0, Radiological Impact Evaluation of EPU on Radiation Monitoring System

5-17. NUREG-0737, Clarification of TMI Action Plan Requirements

5-18. HCGS Annual Radioactive Effluent Release Reports (ARERRs):

   a. 2000 HCGS RERR – 23
   b. 2001 HCGS RERR – 24
   c. 2002 HCGS RERR – 25
   d. 2003 HCGS RERR – 26
   e. 2004 HCGS RERR – 27 (Preliminary)

5-19. NUREG-1048, Safety Evaluation Report Related to the Operation of Hope Creek Generating Station, Docket No. 50-354, October 1984

5-20. NUREG-1437, Volume 1, Generic Environmental Impact Statement for License Renewal of Nuclear Plants

5-21. NUREG-75/038, Supplement I to WASH-1238, Environmental Survey of Transportation of Radioactive Material to and from Nuclear Power Plants, April 1975

5-22. NRC Safety Evaluation Related to Amendment No. 134 to Facility Operating License No. NPF-57, Re: Increase in Allowable Main Steam Isolation Valve (MSIV) Leakage Rate and Elimination of MSIV Sealing System (TAC No. MB1970), October 3, 2001

5-23. NRC Safety Evaluation Related to Amendment No. 146 to Facility Operating License No. NPF-57, Re: Containment Requirements During Fuel Handling and Removal of Charcoal Filters (TAC No. MB5548), April 15, 2003

5-24. HCGS Calculation No. H-1-ZZ-MDC-1929, Revision 0IR0, Fuel Handling Accident Radiological Consequences

5-25. NRC Regulatory Guide 1.183, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors, July 2000

5-26. HCGS Calculation No. H-1-ZZ-MDC-1880, Revision 1IR1, Post-LOCA EAB, LPZ, and CR Doses

5-27. HCGS Calculation No. H-1-ZZ-MDC-1795, Revision 4IR0, Control Rod Drop Accident Radiological Consequences

5-28. HCGS Calculation No. H-1-ZZ-MDC-1854, Revision 1IR0, Main Steam Line Break Accident

5-29. WASH-1238, Environmental Survey of Transportation of Radioactive Materials to and from Nuclear Power Plants, December 1972

5-30. HCGS Environmental Report – Operating License Stage, Volume 2

5-31. HCGS Engineering Evaluation No. H-1-ZZ-MEE-1791, Revision 0, Radiological Environmental Impact of EPU on Uranium Fuel Cycle and Spent Fuel & Radwaste Transportation

5-32. TLG Services, Inc. 2002. "Decommissioning Cost Analysis for the Hope Creek Generating Station. Document P07-1425-0022, Rev. 0."

5-33. Federal Register Volume 53, Number 123, page 24022. June 27, 1988.

6.0 ALTERNATIVES TO THE PROPOSED ACTION

This section evaluates the environmental impacts of alternatives to the HCGS proposed EPU. The proposed EPU would result in an uprate from 3,339 MWt to a maximum of 3,952 MWt, resulting in a gross increase of about 200 MWe. The following discussion includes an assessment of the "no action" alternatives and other alternatives that would result in incremental changes in system generating capacity.

6.1 NO ACTION ALTERNATIVE

PSEG has defined the "no action" alternative as the condition in which the Station continues to operate under current power levels. Under this alternative, HCGS operation and associated impacts would not be different from those currently allowed through the various permits approved by federal, state and local regulatory agencies and PSEG would develop an alternate energy development strategy.

6.2 ALTERNATIVES THAT MEET INCREMENTAL CHANGES IN SYSTEM GENERATING CAPACITY

The Energy Information Administration (EIA, 2002) reports the primary sources of generation in New Jersey in 2002 were approximately the following: nuclear (50%), gas (31%), coal (16%), oil (2%), and other sources (2%). PSEG has concluded that gas- and possibly coal-fired facilities are the only reasonable alternatives to the EPU for incremental increases in generation comparable to the proposed EPU.

PSEG evaluated potential new gas- and coal-fired units for the existing HCGS site. Under this alternative, PSEG would construct a separate generating facility and minimize some environmental impacts by building on previously disturbed land, utilize existing facilities, transmission lines, roads and parking areas, office buildings, and cooling systems, to the extent practicable.

For comparability in analysis, PSEG selected gas- and coal-fired units of equal electric power and equal capacity factors. Therefore, to meet the electrical supply of the proposed EPU, PSEG selected alternative units of about 200 gross MWe. However, it is important to remember that these are hypothetical alternatives and PSEG does not have plans for such construction at HCGS.

6.2.1 Gas-Fired Generation Alternative

PSEG has chosen to evaluate the gas-fired generation alternative using combined-cycle turbines, because this technology has been employed at other sites and appears to be sufficiently economical and feasible for implementation at HCGS. Gas-fired combined cycle turbines are readily available in a standardized unit of about 200 MW and are more economical than customized units. Table 6-1 presents the basic gas-fired alternative characteristics. Employing this alternative would require, at a minimum a new dedicated, high pressure natural gas line that would extend for miles to the Station. In addition, a constant and reliable source of natural gas would have to be located, which may lead to further supply and reliability issues.

6.2.2 Coal-Fired Generation Alternative

Commonwealth Edison Company, in considering an extended power uprate for the Dresden Nuclear Power Station, evaluated a coal-fired alternative (Tetra Tech NUS Inc., 2000). PSEG has reviewed the analysis and believes it to be relevant to the proposed EPU for the HCGS. Thus, PSEG has used site- and New Jersey-specific information and has scaled from the Commonwealth Edison Company analysis, where appropriate, to provide this alternative.

Table 6.2 presents the coal-fired alternative characteristics employed in this evaluation. The emission control technology and percent control assumptions are based on alternatives that USEPA has identified as being available for minimizing emissions. Coal and some other emission control chemicals (e.g., lime/limestone) would probably be delivered via rail or barge that would require further modifications at HCGS.

Table 6-1

Gas-Fired Alternative Characteristics

Characteristic	Basis
Unit size = 200 MW[5] gross[6] : One 137 MW combustion turbine and a 63 MW heat recovery boiler	Chosen to be equivalent to proposed EPU
Unit size = 192 MW net	Assumed a 4% power usage at HCGS
Fuel type = natural gas	Assumed
Fuel heating value = 1,030 Btu/ft^3	2000 value for gas used in New Jersey (EIA, 2000)
Fuel sulfur content = 0.0034 lb/MMBtu	Used when sulfur content is not available (USEPA, 2000a)
NOx control = selective catalytic reduction (SCR)	Best available for minimizing NOx emissions (USEPA, 2000b)
NOx emission factor = 0.0128 lb/MMBtu	Typical for SCR-controlled gas-fired units (USEPA, 2000b)
CO emission factor = 0.0168 lb/MMBtu	Typical for SCR-controlled gas-fired units (USEPA, 2000b)
Heat rate = 8,200 Btu/Kwh	Typical for combined cycle gas-fired units (EIA, 2002)
Capacity factor = 0.75	Assumed same as coal for comparison

[5] MW = megawatt; Btu = British thermal unit; ft^3 = cubic foot; Kwh = kilowatt hour; MM = million; NOx = nitrogen oxides; CO = carbon monoxide

[6] The difference between gross and net size is the amount of electricity consumed at HCGS.

Table 6-2

Coal-Fired Alternative Characteristics

Characteristic	Basis
Unit size = 200 MW[7] gross[8]	Chosen to be equivalent to proposed EPU
Unit size = 192 MW net	Assumed a 4% power usage at HCGS
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxide emissions (USEPA, 1998)
Fuel type = bituminous, pulverized coal	Typical for coal used in New Jersey
Fuel heating value = 12,915 Btu/lb	2000 value for coal used in New Jersey (EIA, 2000)
Fuel ash content by weight = 8.8 percent	2000 value for coal used in New Jersey (EIA, 2000)
Fuel sulfur content by weight = 1.19 percent	2000 value for coal used in New Jersey (EIA, 2000)
Uncontrolled NOx emission = 9.7 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, pre-NSPS with low NOx burner (USEPA, 1998)
Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, pre-NSPS with low NOx burner (USEPA, 1998)
Heat rate = 10,200 Btu/Kwh	Typical for coal-fired, single cycle steam turbines (EIA, 2002)
Capacity factor = 0.75	Typical for small coal-fired units
NOx control = low NOx burners, overfire air and selective catalytic reduction (SCR, 95% reduction)	Best available technology for minimizing NOx emissions (USEPA, 1998, Table 1.1-2)
Particulate control = fabric filters (baghouse 99.9% removal efficiency)	Best available technology for minimizing particulate emissions (USEPA, 1998, Page 1.1-7)
Sox control = wet scrubber-lime/limestone (95% removal efficiency)	Best available technology for minimizing SOx emissions (USEPA, 1998, Table 1.1-1)

[7] MW = megawatt; Btu = British thermal unit; ft^3 = cubic foot; Kwh = kilowatt hour; lb = pound; NSPS = New Source Performance Standards; NOx = nitrogen oxides; CO = carbon monoxide; SOx = sulfur oxides

[8] The difference between gross and net size is the amount of electricity consumed at HCGS.

6.3 ENVIRONMENTAL IMPACTS OF ALTERNATIVES

This section evaluates the potential environmental impacts from the fossil fired alternatives described above.

6.3.1 Gas-Fired Generation Impacts

NRC (1996b) evaluated the environmental impacts from gas-fired generation alternatives in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants and focused on combined-cycle plants. Section 6.2.1 presents the assumptions for defining a combined-cycle gas-fired plant at HCGS.

Land use impacts at HCGS for gas-fired generation would be less than for coal-fired generation because of the following: construction on the existing site, a relatively small facility foot print, and no ash or lime sludge disposal. These attributes would potentially reduce impacts to ecological, cultural, and aesthetic resources when compared to the coal-fired generation alternative. A workforce of 10 to 20 individuals to operate the gas-fired facility would have minimal socioeconomic impacts. Gas-fired generation would result in minimal waste generation and produce minor, if any impacts.

The primary impacts with gas-fired generation appear to be associated with air emissions and potential impacts to ecological and cultural resources from gas pipeline construction.

PSEG estimates the gas-fired generation alternative would have the following annual air emissions:

- SOx, 13 tons per year
- NOx, 47 tons per year
- CO, 62 tons per year
- Total Suspended Particulates (TSP), 7 tons per year as PM_{10} (includes filterable and condensable)

Table 6-3 presents the equations used by PSEG to calculate these emissions, which are based on the plant characteristics provided in Table 6-1.

Air quality impacts of gas-fired generation are different from nuclear generation. A gas-fired plant would emit sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and particulate matter (PM), all of which are regulated pollutants as well as carbon dioxide (CO_2), a potential contributor to global warming. The gas-fired alternative would release similar types of emissions to the coal-fired generation but in lesser quantities.

NOx emissions are the primary focus of the control technology for gas-fired turbines. Emissions of NOx from the electric power industry in New Jersey increased by 4 percent from 1990 to 1999 (EIA, 2001). In 1998, the USEPA (2002b) promulgated the NOx State Implementation Plan (SIP) that required 22 states including New Jersey to substantially reduce their NOx emissions. The NOx SIP imposes a NOx budget to limit the NOx emissions from each state. NJDEP has allocated NOx credits among the existing electrical generators in the state and has set aside a small percentage of credits for new sources. New sources of NOx must obtain enough NOx credits to cover their annual emissions either from the set aside pool or by buying NOx credits from other sources.

Aspects of the Clean Air Act Amendments (CAAA) cap the sulfur dioxide emissions from power plants and provide allowances to each utility. To be in compliance with the CAAA, PSEG must have enough sulfur dioxide allowances to cover its annual emissions. PSEG would probably have to purchase additional allowances from the open market to operate a fossil fuel burning plant at the HCGS site.

The installation of a buried gas pipeline from an identified source to the HCGS site would likely be very costly (e.g., approximately $1 million per mile), time consuming from a permitting perspective, and have potential impacts to ecological and cultural resources, especially the wetlands in the region. PSEG could mitigate some impacts by employing best management practices during construction (e.g., minimizing soil loss, restoring vegetation immediately after the excavation is backfilled, choosing a pipeline route that minimizes interaction with the resources). Installation of the pipeline would probably not create a long-term reduction in the diversity of the plant and animal communities found along the pipeline corridor.

Table 6-3. Air Emissions for Gas-Fired Alternative.

Parameter	Calculation	Result
Annual gas consumption	$1\ \text{unit} \times \frac{137\ \text{MW}}{\text{unit}} \times \frac{8{,}200\ \text{Btu}}{\text{kw-hr}} \times \frac{1{,}000\text{Kw}}{\text{MW}} \times 0.75 \times \frac{\text{ft}^3}{1{,}018\ \text{Btu}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{days}}{\text{year}}$	7,250,233,791 ft^3 per year
Annual Btu input	$\frac{7{,}250{,}233{,}791\ \text{ft}^3}{\text{year}} \times \frac{1{,}018\ \text{Btu}}{\text{ft}^3} \times \frac{\text{MMBtu}}{10^6\text{Btu}}$	7,380,737 MMBtu per year
Sulfur oxides	$\frac{0.0034\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{7{,}380{,}737\ \text{MMBtu}}{\text{year}}$	13 tons per year
Nitrogen oxides	$\frac{0.0128\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{7{,}380{,}737\ \text{MMBtu}}{\text{year}}$	47 tons per year
Carbon monoxide	$\frac{0.0168\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{7{,}380{,}737\ \text{MMBtu}}{\text{year}}$	62 tons per year
Total Suspended Particulates	$\frac{0.0019\ \text{lb}^a}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{7{,}380{,}737\ \text{MMBtu}}{\text{year}}$	7 tons per year

[a] Emission factor for filterable particulate matter (USEPA, 2000, Table 3.1-2a.)

Construction might require preservation of cultural resources. It is more likely that these activities would result in minimal impacts, if any. The greatest impact relative to HCGS would likely be the impacts to the wetlands during construction and maintenance of the pipeline.

6.3.2 Coal-Fired Generation Impacts

The coal-fired alternative defined in Section 6.2.2 would be located on the existing HCGS site on previously disturbed land, which would reduce construction impacts. The alternative assumes the use of the existing cooling water system with additional cooling tower cells that would operate within the existing NJPDES limits and thereby minimize aquatic impacts. Again for this alternative it was assumed that the heat rejection rate would be the same as for the EPU. Socioeconomic impacts are expected to be minimal and similar to those described for the gas-fired generation alternative. The primary impacts associated with coal-fired generation alternative appear to be those associated with air emissions and waste management

PSEG estimates the coal-fired generation alternative would have the following annual air emissions:

- SOx, 587 tons per year
- NOx, 126 tons per year
- CO, 130 tons per year
- Total Suspended Particulates (TSP), 18 tons per year
- PM_{10}, 4 tons per year

Table 6-4 presents the equations used by PSEG to calculate these emissions, which are based on the plant characteristics provided in Table 6-2.

Air quality impacts of coal-fired generation are also different from nuclear generation. A coal-fired plant would emit SOx, NOx, CO and particulate matter, all of which are regulated pollutants as well as carbon dioxide, a potential contributor to global warming. The coal-fired alternative would release similar types of emissions to the gas-fired generation but in greater quantities. The SOx would be emitted in quantities in excess of major threshold quantities. NOx and CO may also be emitted in excess of major threshold quantities.

This alternative may require offsets, the purchase of emission credits, or other control technologies beyond the combination of boiler technology and post-combustion pollutant removal assumed in this analysis. The emission of low levels of mercury and other toxic compounds from coal-fired generation may present other impacts to be addressed. As NRC (1996b) stated, the adverse human health effects from coal combustion have led to relatively recent Federal legislation to address public health issues, such as cancer and emphysema. The NRC also identified global warming, acid rain, ozone transport, and mercury deposition as significant air quality issues associated with coal-fired generation. Obviously, there are numerous, stringent state and federal air pollution control requirements applicable to the construction and operation of a coal-fired plant at the HCGS site with which PSEG would have to comply. These could include visibility impacts on the Brigantine National Wildlife Refuge that could preclude approval of a coal-fired plant at HCGS. This project would be subject to review under the Prevention of Significant Deterioration regulations which would require an extensive assessment of the environmental impacts. PSEG concludes that the coal-fired generation alternative would more likely have greater impacts on air quality than the other alternatives being considered.

Table 6-4. Air Emissions for Coal-Fired Alternative.

Parameter	Calculation	Result
Annual coal consumption	$1\ \text{unit} \times \frac{200\ \text{MW}}{\text{unit}} \times \frac{10{,}200\ \text{Btu}}{\text{kw-hr}} \times \frac{1{,}000\text{Kw}}{\text{MW}} \times 0.75 \times \frac{\text{lb}}{12{,}915\ \text{Btu}} \times \frac{\text{ton}}{2{,}000\text{lb}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{days}}{\text{year}}$	518,855 tons of coal per year
Sulfur oxides	$\frac{38^{a} \times 1.19\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times (1-\frac{95)}{100} \times \frac{518{,}855\ \text{tons}}{\text{year}}$	587 tons per year
Nitrogen oxides	$\frac{9.7\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times (1-\frac{95)}{100} \times \frac{518{,}855\ \text{tons}}{\text{year}}$	126 tons per year
Carbon monoxide	$\frac{0.5\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{518{,}855\ \text{tons}}{\text{year}}$	130 tons per year
Total Suspended Particulates	$\frac{10^{a} \times 7.1\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times (1-\frac{99.9)}{100} \times \frac{518{,}855\ \text{tons}}{\text{year}}$	18 tons per year
PM_{10}[b]	$\frac{2.3^{a} \times 7.1\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times (1-\frac{99.9)}{100} \times \frac{518{,}855\ \text{tons}}{\text{year}}$	4 tons per year

[a] Emission factors for pulverized coal dry bottom, tangentially fired, bituminous Pre-NSPS with low NOx burner (USEPA, 1998, Tables 1.1-3 and 1.1-4)

[b] Particulates having diameter less than 10 microns.

The NRC (1996b) also concluded that the operation of a coal-fired plant would produce substantial solid waste. The coal-fired generation alternative was estimated to consume 518,855 tons of coal per year having with an ash content of 8.8 percent (Tables 6-4 and 6-2). After combustion, most (>99%) of the ash, approximately 45,614 tons per year, would be collected along with approximately 32,005 tons per year of scrubber sludge (based on an annual lime usage of 10,853 tons). PSEG estimates that the disposal of this waste over the next 20 years would require approximately 21 acres of land for disposal based on a 30-foot high waste pile (Table 6-5).

PSEG believes that with proper siting, construction, operation, and monitoring that solid waste disposal is feasible for the HCGS site. There is potential space at the HCGS site for converting previously disturbed or unoccupied land (NRC, 1984 cites approximately 300 acres of unused land at the HCGS site) to waste disposal however there might be substantial engineering and public relation issues associated with siting a waste disposal facility at the HCGS site. NJDEP has strict standards for disposal facilities which might result in substantial costs or add to the complexity of the operation. The landfill would likely be above grade due to its close proximity to the Delaware River and groundwater table. PSEG believes these issues are greater than for the other alternatives and could have a local effect but are manageable.

Table 6-5. Estimate of Solid Waste Pile based on Coal-Fired Generation Alternative.

Parameter	Calculation	Result
SO_2 generated	$\frac{1.19 \text{ tons S}}{100 \text{ tons coal}} \times \frac{518{,}855 \text{ tons}}{\text{year}} \times \frac{64.1 \text{ tons } SO_2}{32.066 \text{ tons S}}$	12,343 tons SO_2 generated
SO_2 removed	$\frac{1.19 \text{ tons S}}{100 \text{ tons coal}} \times \frac{518{,}855 \text{ tons}}{\text{year}} \times \frac{64.1 \text{ tons } SO_2}{32.066 \text{ tons S}} \times \frac{95}{100}$	11,725 tons SO_2 removed
Ash generated	$\frac{8.8 \text{ tons ash}}{100 \text{ tons coal}} \times \frac{518{,}855 \text{ tons}}{\text{year}} \times \frac{99.9}{100}$	45,614 tons ash per year
Annual lime consumption	$\frac{12{,}343 \text{ tons } SO_2}{\text{year}} \times \frac{56.1 \text{ tons CaO}}{64.1 \text{ tons } SO_2}$	10,853 tons CaO per year
Annual calcium sulfate generation	$\frac{11{,}725 \text{ tons } SO_2}{\text{year}} \times \frac{172 \text{ tons } CaSO_4{*}2H_2O}{64.1 \text{ tons } SO_2}$	31,462 tons $CaSO_4{*}2H_2O$/yr
Annual scrubber waste generation	$\frac{10{,}853 \text{ tons CaO}}{\text{year}} \times \frac{100-95}{100}$ 31,462 T $CaSO_4{*}2H_2O$	32,005 T scrubber waste/yr
Total volume of scrubber waste	$\frac{32{,}005 \text{ tons}}{\text{year}} \times 20 \text{ years} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{144.8 \text{ lb}}$	8,841,160 ft^3 scrubber waste
Total volume of ash generated	$\frac{45{,}614 \text{ tons}}{\text{year}} \times 20 \text{ years} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{100 \text{ lb}}$	18,245,600 ft^3 ash
Total volume of solid waste	8,841,160 ft^3 18,245,600 ft^3	27,086,760 ft^3 solid waste
Waste pile area (acres)	$\frac{27{,}086{,}760 \text{ } ft^3}{30 \text{ ft high}} \times \frac{\text{acre}}{43{,}560 \text{ } ft^2}$	21 acres solid waste

Calculation Assumptions:
100 perecnt combustion of coal; density of coal bottom ash is 100 lb/ft^3; density of calcium sulfate dihydrate is 144.8 lb/ft^3; plant life=20 years; and waste pile height =30 ft.

7.0 ENVIRONMENTAL COMPLIANCE PERMITS AND CONSULTATIONS

Table 7-1 lists the major environmental authorizations that PSEG has obtained for current HCGS operations. In this context PSEG uses the term "authorizations" to include permits, licenses, approvals, and other entitlements.

Attachment B includes a list of the relevant environmental permits for HCGS.

Table 7-1

Hope Creek Generating Station Major Environmental Authorizations for Current Operations

Agency[9]	Authority	Requirement	Number	Expires	Activity Covered
USNRC	Atomic Energy Act	Facility Operating License and Docket Number	NPF-57 and 50-354	12/20/26	Operation of the plant
NJDEP	Federal Clean Water Act	NJPDES Permit	NJ0025411	2/31/08	Water discharges to Delaware River
NJDEP	Water Supply Management Act	Water Allocation Permit	2216P	1/31/10	Groundwater withdrawal for industrial cooling and potable purposes
NJDEP	Federal Clean Air Act	Air Operating Permit	BOP030001	2/1/10	Air emissions
DRBC	Delaware River Basin Compact	DRBC Permit	D-73-193 CP (Revised)	Not Applicable	Construction and operation of the plant, stream quality objectives, surface water withdrawal, and temperature and heat dissipation area related to thermal discharge
DRBC	Delaware River Basin Compact	DRBC Permit	D-90-71	11/15/10	Groundwater withdrawal
USACOE	Federal Clean Water Act, Section 404 (33 U.S.C. 403)	USACOE Permit	OP-R-199501755-45	12/31/06	Waterfront development desilting & dredging
USEPA	Resource Conservation Recovery Act	Hazardous Waste Generator Permit	NJD077070811	Not Applicable	Hazardous waste management

9 USNRC = United States Nuclear Regulatory Commission; NJDEP = New Jersey Department of Environmental Protection; DRBC = Delaware River Basin Commission; USACOE =United States Army Corps of Engineers; USEPA = United States Environmental Protection Agency.

8.0 SUMMARY COMPARISON

The extended power uprate will not result in significant impacts to the environment. It does not result in significant new environmental hazards or increase the risks of environmental hazards that were previously evaluated. The environmental impacts and adverse effects identified in the Summary and Conclusions Section of the FES for HCGS operation continue to encompass plant operation at extended power uprate conditions. The proposed changes do not, individually or cumulatively, affect the environment. There is no significant change in the types or amounts of plant effluents. Extended power uprate does not involve significant increases in individual or cumulative occupational radiation exposure.

The effect of the extended power uprate on the environment does not prevent continued compliance with any environmental permit or modified permit. With the exception of the hourly particulate emissions from the HCCT, none of the license conditions for environmental protection will be changed for extended power uprate. No water effluent limits will be exceeded and the present discharges which are below these limits will not be significantly changed. The extended power uprate does not involve a significant increase in the discharge of hazardous substances, contaminants, or pollutants and does not involve the use of any new hazardous substances, contaminants, or pollutants.

The extended power uprate does not involve any significant changes to air quality or water quality. It does not result in any changes to land use and has no effect on groundwater use. The amount of water withdrawn and consumed from the Delaware River remains within that previously evaluated by the NRC and the NJDEP. The increase in discharge temperature has an insignificant effect on Delaware River temperatures and will not result in any significant changes to aquatic biota. Extended power uprate will not involve new or different discharges of contaminants and does not involve changes to any bioaccumulation effects for aquatic organisms. The quality of drinking water is not affected.

Extended power uprate does not involve any changes to wildlife habitat and does not result in any significant impacts to aquatic or terrestrial biota. There are no deleterious effects on the diversity of biological systems or the sustainability of species due to extended power uprate. Extended power uprate does not involve additional changes to the stability or integrity of

ecosystems. Extended power uprate does not affect the previous conclusions on impingement or entrainment. Extended power uprate does not affect HCGS compliance with Sections 316(a) or 316(b) of the Federal Water Pollution Control Act.

Extended power uprate does not significantly change any doses to the public from radiological effluents, and offsite doses will continue to be well within regulatory limits. The Safety Evaluation for HCGS concluded that the release of radioactive material in liquid and gaseous effluents from HCGS will meet the requirements of 10 CFR 50 for keeping such effluent levels to unrestricted areas as low as reasonably achievable and will result in doses that are a small percentage of the 10 CFR 20 limits. This conclusion was based on assumptions for effluent releases that bound releases expected for extended power uprate. Occupational dose will be maintained well within regulatory limits, and changes in radiation levels will not significantly increase the dose to the HCGS work force. Accident doses under extended power uprate conditions remain well within the applicable regulatory limits. Extended power uprate does not involve significant increases in the probability or consequences of previously evaluated environmental accidents.

The environmental effects of decommissioning were evaluated in the FES and it was determined that the primary contributor to environmental impact was the dose from transportation of waste to disposal facilities. As concluded in Section 5.0 above, the impact of EPU on transportation of fuel and radioactive waste is not significant. Extended power uprate does not affect the ability to maintain sufficient financial reserves for decommissioning.

This environmental evaluation has demonstrated that extended power uprate does not involve environmental impacts that differ significantly from those previously evaluated. The environmental impacts of HCGS operation with extended power uprate continue to be bounded by the FES or bounded by other appropriate and applicable regulatory criteria. Where environmental impacts differ from those previously evaluated, these impacts have been shown to be insignificant and well within regulatory environmental acceptance criteria.

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ATTACHMENT A

HOPE CREEK GENERATING STATION BIOLOGICAL TOXICITY TESTING DATA

BIOLOGICAL TOXICITY TESTING DATA

DATE OF TOXICITY TEST	TYPE OF TOXICITY TEST	RESULT OF TEST
09/01/98 **	Acute Toxicity Test	LC 50 >100%
01/15/99 **	Acute Toxicity Test	LC 50 >100%
04/24/99 **	Acute Toxicity Test	LC 50 >100%
06/15/99 **	Acute Toxicity Test	LC 50 >100%
09/01/98 **	Chronic Toxicity Test	IC 25 > 100%
01/15/99 **	Chronic Toxicity Test	IC 25 > 100%
04/24/99 **	Chronic Toxicity Test	IC 25 > 100%
06/15/99 **	Chronic Toxicity Test	IC 25 > 100%
06/26/01	Acute Toxicity Test	LC 50 >100%
06/26/01	Chronic Toxicity Test	IC 25 > 100%

** Whole Effluent Toxicity Characterization Study testing conducted in accordance with NJPDES Permit NJ0025411, Part IV-B/C, Sections 1.D and 1.E and reported to the NJDEP on October 5, 1999.

ATTACHMENT B

HOPE CREEK GENERATING STATION ENVIRONMENTAL PERMITS

HOPE CREEK GENERATING STATION
Environmental Permits

PERMIT/PURPOSE	NUMBER
Air Pollution Control Permits (Program Interest No. 65500)	
Title V Air Operating Permit	BOP 030001
Potable Water Supply	
Public Water Supply No.	1704306
Groundwater Diversion Permit - Production Wells	2216P
DRBC Ground Water Withdrawal	D-90-71
Treatment Works Approvals	
Cooling Tower TWA	Waiver
Liquid Radwaste Treatment System TWA	Waiver
Low Volume and Oily Waste System TWA	Waiver
Sewage Treatment Plant TWA	Waiver
Hazardous Waste Management Program	
Hazardous Waste Generator	NJD077070811
Medical Waste Generator	34571

HOPE CREEK GENERATING STATION
Environmental Permits

PERMIT/PURPOSE	NUMBER
Relevant Environmental Permits	
CAFRA	74-014
Riparian License	74-46
Riparian License (Access Road)	68-12
Type "B" Wetlands Permit	W74-042
Waterfront Development (Dredging & Desilting)	OP-R-199501755-45
Waterfront Development (Maintenance Dredging)	1704-90-0001.8
DRBC Docket Decision (STP Allocation)	D-85-60CP
DRBC Docket Decision (STP)	D-87-70
DRBC HC Construction	D-73-193CP
Laboratory Certificate	17451
Air Navigation Determination	82-AEA-0822-OE
USNRC Facility Operating License	NPF-57
USNRC Facility Operating License (EPP)	50-354
Centralized Warehouse	91-5585-4
DPCC/DCR	170400041000
Surface Water Discharge Permit (NJPDES)	NJ0025411

HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
LIST OF COMPLETED AND PLANNED MODIFICATIONS

The following is a list of completed and currently planned modifications necessary to support Extended Power Uprate (EPU). The planned modifications are to be implemented before restart from Hope Creek refueling outage RF14, currently scheduled for Fall 2007. The planned modifications listed are subject to change based on evaluations performed as part of PSEG's design change process. As such, the list is not a formal commitment to implement the modifications exactly as described. Additionally, various setpoint changes and changes to indicating ranges on certain control room and in-plant instrumentation, which may be necessary, are not listed. Implementation of these modifications will be in accordance with the requirements of 10 CFR 50.59.

Completed Modifications

- Additional 500 kV circuit breaker in Hope Creek switchyard
- Cooling tower fill and flow distribution modifications
- Low Pressure Turbine replacement
- Electrohydraulic Control (EHC) and Turbine Supervisory Instrumentation (TSI) replacement
- Main Transformer replacement
- Main Generator Stator Water Cooling upgrade
- Turbine Moisture Separator upgrade
- Piping Vibration Monitoring
- Average Power Range Monitor (APRM) and Rod Block Monitor (RBM) flow-biased trip reference card replacement

Planned Modifications

- Isolated Phase Bus Duct Cooling modification
- High Pressure Turbine replacement
- Feedwater Heater Dump Valve replacements
- Steam Jet Air Ejector modification
- Moisture Separator and Feedwater Heater rerating
- Pipe Support modifications (where required)

Attachment 7

LR-N05-0258
LCR H05-01

HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
STEAM DRYER EVALUATION

PSEG
Nuclear LLC

Hope Creek Generating Station

Extended Power Uprate

Steam Dryer Evaluation

November 2005

Table of Contents

HCGS STEAM DRYER EVALUATION

Executive Summary

The HCGS steam dryer is a curved hood design that was further upgraded prior to commercial operation. It has been properly inspected on a recurring basis and has shown no flow induced vibration (FIV) damage to date. PSEG used the Acoustic Circuit Model (ACM) load transfer methodology to calculate steam dryer loads at seven power levels between 50% and 100% Current Licensed Thermal Power (CLTP). The ACM methodology was benchmarked at Quad Cities 2 using an instrumented steam dryer to compare predicted and actual loads. The most limiting load, 96% CLTP, was inputted into the HCGS specific steam dryer finite element model (FEM). The CLTP analysis shows that the highest stressed component on the steam dryer has a design margin 2.6 when considering uncertainties. This value was 3.7 prior to considering uncertainties.

PSEG is aware of industry concerns with the operation of steam dryers under Extended Power Uprates (EPU) conditions. The EPU power ascension test plan will incorporate predetermined hold points above CLTP to allow for review and confirmation that dryer loads remain below acceptable values. PSEG will rely on the ACM load transfer methodology, using strain gage readings in the Main Steam Line (MSL), to calculate steam dryer loads during this initial power ascension to EPU. PSEG will validate during this power ascension that loading, including uncertainties, will not result in unacceptable steam dryer fatigue stresses. Although a 2.6 margin provides a significant margin for a 15% power increase, PSEG is reviewing the options to demonstrate a higher margin prior to EPU operation by (1) reducing the uncertainty of the strain gage readings due to their present location and arrangement and (2) justifying increased dampening on the steam dryer. The CLTP FEM analysis assumed only 1% dampening, which is considered a conservative low number.

To further reduce risks in the power ascension testing, PSEG is undertaking proactive steps to minimize the unknowns associated with relief valve acoustic resonance, which has been identified as the primary loading that caused damage at Quad Cities and Dresden steam dryers. This effort includes determining the acoustic frequency for the HCGS relief valves, FEM analysis of the steam dryer prior to power ascension to determine the maximum allowable magnitude at that frequency, and pursuing analytical and testing methodologies to predict the steam line velocity (power level) that results in the onset and peak conditions of relief valve acoustic resonance.

This Attachment summarizes actions completed or currently planned to ensure the integrity of the steam dryer at the EPU condition.

Introduction

In June 2002, a BWR 3 was operating at approximately 113% of original licensed thermal power (OLTP) when it experienced a failure of a steam dryer cover plate resulting in the generation of loose parts, which were ingested into a main steam line (MSL). The most likely cause of this event was identified as high cycle fatigue caused by a flow regime instability that resulted in localized high frequency pressure loadings near the MSL nozzles. In May 2003, the same plant experienced a second steam dryer failure. This second failure occurred at a different location with the root cause identified as high cycle fatigue resulting from low frequency pressure loading.

In August 2002, General Electric Company (GE) issued a Services Information Letter (SIL) (reference 1) that recommended monitoring steam moisture content (MC) and other reactor parameters for BWR 3-style steam dryers. Reference 1 also recommended inspection of the cover plates at the next refueling outage for those plants operating at greater than OLTP.

In October 2003, a hood failure occurred in the sister unit to the BWR 3 that had experienced the previously noted failures. This unit was also operating at EPU conditions. The observed hood damage and associated root cause determination were virtually the same as the May 2003 failure described above. Subsequent inspections of the above two plants and other BWRs identified incipient and extant cracking at various locations on the dryer.

Reference 2 broadened the earlier recommendations for BWR 3-style steam dryer plants and provided additional recommendations for BWR 4 and later steam dryer design plants planning to or already operating at greater than OLTP. Following this revised guidance, inspections were performed on plants operating at OLTP, stretch uprate (5%), and extended power uprate (EPU) conditions. These inspections indicated that steam dryer fatigue cracking could also occur in plants operating at OLTP. Reference 2 described additional significant fatigue cracking that has been observed in steam dryer hoods and provided inspection and monitoring recommendations for all BWR plants.

BWR Fleet Operating History

Steam dryer cracking has been observed throughout the BWR fleet operating history. The operating environment has a significant influence on the susceptibility of the dryer to cracking. Most of the steam dryer is located in the steam space with the lower half of the skirt immersed in reactor water at saturation temperature. These environments are highly oxidizing and increase the susceptibility to inter-granular stress corrosion cracking (IGSCC). Average steam flow velocities through the dryer vanes at rated conditions are relatively modest (2 to 4 feet per second). However, local regions near the steam outlet nozzles may be continuously exposed to steam flows in excess of 100 fps. Thus, there is concern for fatigue cracking

resulting from flow-induced vibration (FIV) and fluctuating pressure loads acting on the dryer. In addition to the recent instances described above, steam dryer cracking has been observed in the following components at several BWRs: dryer hoods, dryer hood end plates, drain channels, support rings, skirts, tie bars, and lifting rods. These crack experiences have predominately occurred during OLTP conditions, and are briefly described in Reference 2.

<u>BWROG recommendations</u>

The BWR Owners Group in September 2004 issued Reference 3. Sections 3.5 and 3.6 of that document address steam dryer loads and inspections/evaluations, respectively. The two recommendations specific to steam dryers are cited below.

- An evaluation of steam dryer loads for EPU conditions should be made prior to implementation of EPU. Modifications of the dryer or bases for not making modifications should be made based on the results of this evaluation.
- Follow the inspection and monitoring recommendations made by the GE SIL (Reference 2) and by the EPRI BWR vessel internal project (VIP) steam dryer inspection guidelines (Reference 4).

HCGS plans to follow the inspection recommendations in Reference 2. PSEG is also evaluating the inspection recommendations made by Reference 4 currently under NRC review, for incorporation into planned dryer inspections.

<u>HCGS Steam Dryer</u>

<u>HCGS History</u>

The HCGS reactor steam dryer went into service with the startup of the plant in 1986. Since start-up, HCGS has concentrated on maintaining water chemistry in a manner that reduces the occurrence of IGSCC. HCGS has incorporated zinc injection since startup and has been on hydrogen water chemistry for several years. This has resulted in relatively few IGSCC issues being identified for components within the Reactor Pressure Vessel. The steam dryer has benefited from this improved water chemistry. IGSCC-type indications have not been observed on the HCGS dryer to any great extent as noted below.

<u>HCGS Steam Dryer Inspections</u>

HCGS performs visual inspections of its steam dryer per BWRVIP guidelines on a recurring basis. During the latest refueling outage (RF-12 in November 2004), visual inspections of the HCGS steam dryer were performed per the recommendations of supplement 1 to Reference 1. The few HCGS steam dryer indications observed during inspections performed prior to and through RF-12 are listed below:

1. Support ring, 205°, horizontal crack, found in RF07. Measured every outage since. RF07 through RF10 measured at 2.25 inch. RF11 measured at 2.87 inch. RF12 measured at 2.25 inch. The RF11 measurement was discounted. This indication has been dispositioned as IGSCC due to residual stress from cold forming of the support ring and its proximity to the upper weld Heat Affected Zone (HAZ). No growth observed since discovery.
2. Skirt, 5°, horizontal weld below the dryer support lug, found in RF10. Horizontal crack in the HAZ below the weld. Measured RF10, 11, and 12. All measurements 0.75-inch. This indication has been dispositioned as IGSCC due to residual stress from welding. No growth observed since discovery.
3. Lifting lug, 220°, upper support bracket, found broken on one side in RF11. During RF12 the upper bracket was removed. Left less than one-inch stub. Justification for removal on file.
4. Support ring, 20°, on top, radial 0.625 inch (from edge to hood weld) and down side vertical 0.75 inches. Crack thought to be started on top and side shows depth. Identified during RF12. This indication has been dispositioned as IGSCC due to residual stress from cold forming of the support ring and its proximity to the weld HAZ.

None of these indications approach the critical flaw size. They will be reevaluated periodically as required by their current flaw evaluations.

A key finding is that no indications have been found on the HCGS dryer areas indicating FIV damage. Specifically, no damage has been found on the outer hoods, cover plates, tie bars, and side plates. As discussed below, Hope Creek has the most robust type of steam dryer (curved hood) and this dryer has been upgraded and reinforced in the areas of greatest FIV concern.

<u>HCGS Steam Dryer Design</u>

The steam dryer at the Hope Creek Generating Station (HCGS) is typical of the late BWR 4/5 curved hood design with some notable exceptions. Prior to operation, the HCGS steam dryer was modified as follows to improve its structural integrity:

- The 0.125-inch thick outer hoods were replaced with 0.5-inch hoods. In addition, the weld attaching the outer hoods to their internal, vertical hood supports was strengthened.
- The 0.1875-inch thick central end plates, on the outlet of the inner hoods, were replaced with 0.5-inch plates.
- The 0.5 by 1-inch tie bars, spanning across the top of the vane assemblies, were replaced with an increased number of 2 by 2-inch tie bars. Seven (7) bars tie the outer vane assembly to its middle vane assembly. Nine (9) bars tie the middle

vane assembly to its inner vane assembly. Five (5) bars tie the two inner vane banks to each other.

- 0.187-inch thick reinforcing strips were added at the outer edges of the middle and inner 0.125-inch thick hoods where they are welded to their 0.250-inch end plates.

HCGS Steam Dryer Comparison to Dryers Operating at EPU

Dryer design and steam velocities have both been identified as contributors to dryer failures and the subsequent generation of loose parts.

The HCGS steam dryer curved hood design is a significant upgrade to the earlier, square hood dryers that failed at Quad Cities and Dresden. These upgrades include improved flow characteristics and significantly improved structural strength in the upper part of the dryer.

The square hood design has 4-foot high dryer vanes, sharp 90° corners at various flow points, and includes a steam dam (raised plate perpendicular to the top of the dryer). This design inherently causes turbulence as the steam flows through the steam dryer into the reactor steam dome. Furthermore, the square hood design results in turbulence as the steam flows from the steam dome towards the MS nozzles since the steam encounters the outside 90° corners of the outer hoods. The curved hood design has 6-foot high vanes, eliminates the 90° corners, and eliminates the steam dam, all of which provide a distinct advantage in reducing turbulence.

The significant structural failures in the Quad Cities and Dresden dryers were at the outer hood, facing the MS nozzles. The square hood design initially used internal bracing, which provided support to the hoods only at the upper corner of the hood. The curved hood dryer uses interior, vertical support plates, which provide continuous support along the entire height of the hood and eliminate the need for external gusset plates. The HCGS outer hoods consist of 0.5-inch thick bent plate welded to 0.375-inch thick end plates and, at the bottom, to a 0.375-inch thick horizontal cover plate.

Another advantage of the curved hood design is that it has a total of four wide drain channels welded to the outside of the dyer skirt. Each drain channel spans approximately 45 degrees along the circumference of the skirt and spans nearly the full height of the skirt (from the bottom of the upper support ring to just above the bottom ring). These four wide drain channels provide added stiffness to the skirt.

The table below summarizes steam dryer design and Main Steam line (MSL) velocities for BWR plants that have received extended power uprates and provides post EPU steam dryer experience. HCGS information is included for comparison

Reactor Type	Station/Plant Dryer Design	MSL Velocities	EPU Operation	Comments
BWR 3	Dresden 2, 3 Square hood	@ OLTP – 168 fps @ EPU 202 fps	117% OLTP	Failure in the outer hood area.
BWR 3	Quad Cities 1, 2 Square hood	@OLTP 168 fps @EPU 202 fps	117% OLTP	Failure in the outer hood area.
BWR 4	Brunswick 1, 2 Slanted hood	@ OLTP – 129 fps @EPU – 149 fps	120% OLTP	No cover plate/hood fatigue failures.
BWR 4	Hatch 1, 2 Slanted hood	@OLTP H1 – 119 fps H2 – 121 fps @EPU H1 – 134 fps H2 – 140 fps	115% OLTP	No cover plate/hood fatigue failures
BWR 4	HCGS Curved hood	@CLTP – 145 fps @EPU – 167 fps	CLTP = 101.4% OLTP	EPU of 115% CLTP requested

The slanted hood design has not had any FIV failures at EPU. Brunswick units are currently operating at 120% of OLTP. Brunswick Unit 1 had operated for an entire fuel cycle at 113% OLTP prior to increasing power to 120% OLTP. Its dryer was inspected after a full cycle of 113% operation and no deleterious FIV effects were identified. Brunswick Unit 1 has now operated near 120% OLTP for over a year with no observable indications of steam dryer failure. The Hatch units have operated at 113% OLTP conditions since November 1998 without evidencing FIV failures.

The curved hood design at HCGS is an improvement on the slanted hood design used in earlier BWR 4 units. The curved hood design is also used in BWR 5s and 6s. Similarities include 6-foot high dryer vanes, internal, vertical support plates, and elimination of the upper dam. The primary difference is that the curved hood uses a single bent plate rather than four straight plates in forming the hood.

Per Reference 2, the only reported fatigue failures for the curved hood steam dryers were in the weld joint between the 0.125-inch thick middle curved hood and its 0.25-inch thick end plates. These occurred at OLTP and, in one case, at 5% stretch power. As stated in the previous section, this area on the middle and inner hoods

was reinforced at HCGS prior to the start of commercial operation. This detail received careful modeling during the HCGS finite element model (FEM) preparation described later.

HCGS Steam Dryer Evaluation

For the HCGS EPU, two methodologies are being utilized to evaluate the HCGS steam dryer. Both of these are plant specific.

Industry experience shows that significant steam dryer loads are generated in the MSL piping due to turbulence and vortexing at the various MSL branch connections. The turbulence may result in acoustical resonance at some of the branch lines, which in turn may be further amplified by the piping geometry, and may result in pressure pulsation back into the steam dome area. The analysis includes a model of the HCGS main steam system including the steam dome and steam dryer in the reactor pressure vessel, and is herein referred to as the acoustic circuit model (ACM). The loads generated by the ACM are applied to a finite element model of the HCGS steam dryer to calculate resulting fatigue stresses. HCGS is using Continuum Dynamics Incorporated (CDI) to produce the ACM analysis.

The second analysis models the flow from the outlet of the steam separators, thru the steam dryer and reactor dome, and into the MS nozzles. This information will be used to understand if the higher steam flows would create any new turbulence phenomena in the steam dryer. As discussed earlier, the HCGS steam dryer design is a curved hood that minimizes turbulence as compared to the square hood. Also, the curved hood design does not have any external gussets or square edges that would create added turbulence at the locations of peak velocity in the steam dome, the entrance of the MS nozzles. HCGS is using Fluent Incorporated to develop a computational fluid dynamics (CDF) model of these areas for HCGS.

Acoustic Circuit Model (ACM)

Previous analysis of main steam line pressure data at other BWRs shows the presence of pressure pulsations at discrete frequencies, which suggests that deterministic mechanisms are active in the MS system. As stated in an ASME Journal Of Pressure Vessel Technology article (Reference 5):

> "High velocity flow past a cavity such as the stub of a closed SRV creates vortices which, under the right conditions, can couple with the acoustic resonance of the stub. Thus relatively small vortex pulsations can be amplified...."

In a fluid system with many junctions and branch lines of various lengths and diameters, a strictly analytical approach cannot be relied on to determine if the vortexing across the various branch lines will create acoustic resonance at that branch line, and furthermore, if the acoustic resonance in a branch line is amplified or attenuated by the piping system.

The ACM being used by HCGS was developed by CDI. This methodology requires measured in-plant data to detect and measure plant specific, pressure pulsation loads. The measurements for HCGS are from strain gages in the MSLs, which provide the magnitude and frequency of the pressure pulsations in the MSLs. CDI's analytical methodology then calculates the steam dryer loads using the measured MSL pressure pulses. As such, the steam dryer loading reflects all sources and does not rely on an analytical approach to determine what the sources are.

The CDI methodology was validated by Exelon through benchmarking the CDI results against an instrumented steam dryer at Quad Cities 2 and the results were documented in Reference 6.

Finite Element Model (FEM)

The plant specific HCGS FEM benefited significantly from the availability on-site of the abandoned HC Unit 2 steam dryer. PSEG verified that the Unit 1 dryer and the abandoned Unit 2 dryer were identical in design and fabrication prior to on-site, field modifications, which were only done for Unit 1 dryer.

CDI generated an ANSYS model of the HCGS steam dryer from detailed measurements of the abandoned HCGS Unit 2 steam dryer supplemented by available drawings and detailed information on the field modifications performed for the Unit 1 dryer. The entire steam dryer was modeled including the skirt and the water at the lower portion of the skirt.

The FEM used for the CLTP analysis consists of:

Total Nodes	99,868
Total Elements	86,974
Total Body Elements	50,499
Total Contact Elements	36,475
Element Types	13
Thicknesses	118
Contacts	152

The model consists of 128 bodies. Structural parts with one dimension significantly smaller than the other two dimensions were modeled with shell elements. Other parts, such as support rings, tie bars, and reinforcement bars were modeled with solid elements. Weld details have been added to the most highly stressed welds. Specifically, the critical welds were modeled as solid elements to more accurately calculate the stresses at the weld.

Steam Dryer CLTP Acoustic Loads

During RF12, the HCGS MSLs were instrumented as the first step in a comprehensive MSL monitoring program that uses 16 strain gages to determine hoop stress from pressure pulsations. The strain gages were installed at eight

locations on horizontal runs in the MS tunnel, downstream of the flow venturi and MSIVs. This consisted of two locations per MSL 50 feet apart to determine the attenuation of the pressure pulsation in the MSL. Each location consisted of two strain gages both located at 90° along the pipe circumference (with 0° being at the top of the pipe). The two strain gages were wired together to obtain an average signal for that location. There were no strain gage failures during the testing.

To provide a comprehensive understanding of power trends, strain gage data was taken and loads developed for 50, 65, 76, 90, 96, 98, and 100% of CLTP. This effort was documented in Reference 7. The specific ACM load transfer used for HCGS is the "Minimum Error Model" described in Reference 6.

Since the strain gages were only located at one location along the circumference, the resulting strain would measure not only internal pressure pulses (e.g., acoustical loading) but also pipe bending due to vibration. PSEG contracted with Structural Integrity Associates (SIA) to review the strain gage data and the power spectral density (PSD) versus Hz information subsequently calculated by CDI. All the loads were retained with the exception of a discrete 54 Hz frequency at 50% power that was judged to be due to vibration of the piping based on the inconsistent presence of the loading between upstream and downstream strain gages (Reference 8).

The results of the CDI analyses for the seven (7) power runs show that there are loads below 50 Hz at all power levels. Less than 50 Hz is considered turbulence. The < 50 Hz loads change with power but there is no clear trend of turbulence loads increasing with power.

When considering all frequencies, the maximum loading peaked at 96% CLTP. However, the primary cause of this peaking at 96% power was the loading at a discrete frequency at 72 Hz. The loading at this frequency dropped at 98% power and was not present at 100% CLTP. There were no discrete frequencies above 50 Hz at 100% CLTP. A frequency of 72 Hz is well below the expected acoustic frequency of the Hope Creek relief valves.

Steam Dryer Stresses with CLTP Acoustic Loading

The seven power runs were reviewed, and the highest load (96% CLTP) was applied to the HCGS FEM.

A high resolution loads prediction was made over a grid mesh of three inch spacing across all surfaces of the steam dryer.

A conservative 1% dampening was applied throughout the entire dryer. This is considered the minimum dampening for a welded structure (PSEG will investigate crediting higher dampening factors, consistent with FEMs done by others, for evaluating EPU loads).

The FEM analysis is documented in Reference 9. The table below tabulates the calculated "maximum stress" and "alternating stress" for the six most highly stressed components. The "maximum stress" is the peak stress estimated for normal conditions, which includes "alternating stress" and dead weight. The margins are extracted from Table 6.3 of Reference 9. The margin is the ratio of the allowable value over the calculated stress value. For welds, the reported margin includes a 1.8 multiplier to account for stress intensification in the weld.

Six Most Highly Stressed Components	Maximum Stress (psi)	Design Margin Max Stress	Alternating Stress (psi)	Design Margin Alternating Stress
Drain channel on skirt (lower portion)	4,155	6.6	2,054	6.6
Weld drain pipe to drain trough plate	3,648	4.1	675	11.2
Drain trough bottom plate – near drain pipe	3,216	8.5	696	19.5
Weld hood support plate junction with vane bank	2,893	5.2	366	20.6
Weld outlet plenum end plate to trough bottom plate	2,685	3.7	394	19.2
Inner hood curved plate	2,450	7.5	1,270	10.7

The lowest margin for "maximum stress" is 3.7. The lowest margin (most limiting component) for alternating stress is 6.6. The allowable value used for alternating stress is 13,600 psi (References 9 and 10).

CLTP Uncertainty Discussion

The uncertainty analysis considers the error from the following sources:

- Strain gage accuracy
- ACM load transfer methodology
- FEM accuracy

Strain Gage Accuracy

Subsequent to the installation of the strain gages, PSEG learned that the location and arrangement of the strain gages are not optimal. The location in the MS tunnel (selected to reduce radiation exposure and minimize risk of strain gage failures) results in a higher uncertainty. CDI estimates that the uncertainty is 42% (Reference 7).

The HCGS instrumentation consists of two strain gages at one location along the circumference of the pipe. SIA reviewed the potential impact of a strain gage at this single location versus a more accurate arrangement of four strain gages spaced 90° apart along the circumference using Quad Cities information. The Quad City data showed that the single strain gage reading was between 1.16 to 2.43 times higher than the averaged reading for four strain gages spaced at 90° along the circumference (Reference 8). On an average, the single location read 1.7 times higher than the averaged reading for that MSL. This agrees with the logic that the single strain gage does not compensate for strain due to pipe bending and, thus, over predicts the strain assumed for internal pressure pulsations. PSEG has data that confirms that there is vibration in the MS tunnel piping.

ACM Load Transfer Methodology

The specific CDI ACM load transfer used for HCGS is the "Minimum Error Model" described in Reference 6. As a result of the model refinements against an instrumented steam dryer, the error is considered minimal. CDI estimates that the uncertainty is 8% (Reference 6).

FEM Accuracy

The FEM is specific for HCGS and all known details were modeled. The resulting CLTP stresses are considered conservative since the analysis was performed at a conservative 1% dampening throughout the dryer.

Summary of CLTP Uncertainties

The uncertainty due to the strain gage location (42%) and ACM model (8%) are combined as the square root of the sum of the squares (SRSS) to yield 43% uncertainty.

The above result conservatively neglects the conservatism introduced by having the strain gages at a single point along the circumference of the pipe, which based on

Quad Cities data, results in a significant over prediction of the loads. Also, the three most highly stressed components are directly affected by skirt vibration, and it is judged that a higher, more realistic dampening value than the 1% assumed would significantly reduce the skirt vibration.

Steam Dryer Margin at CLTP

The 43% uncertainty on ACM loads is not a concern for CLTP since the FEM analysis shows compensating margin. Since the maximum stressed component had a design margin of 3.7, increasing the loading by 1.43 results in a revised design margin of 2.6.

Analyses to Prepare for EPU ACM Loading

The CLTP results show that the HCGS steam dryer can withstand a 2.6 increase in loads. PSEG expects that this margin will increase when improvements in dampening factors and strain gage orientation are included.

Nevertheless, the PSEG aim is to gain, to the extent reasonably possible, as much information about the potential EPU loading prior to EPU power ascension so as to minimize the risk and uncertainty during EPU power ascension. The following items were considered:

- Based on Exelon experience at Quad Cities and Dresden, PSEG concluded that the principal risk to the HCGS steam dryer at EPU conditions is from high frequency acoustic loading from the relief valve branch lines. Dresden experienced this phenomenon below CLTP, and Quad Cites experienced it above CLTP. PSEG reviewed the discrete frequencies for the HCGS 50% to 100% CLTP loads and determined that there was no indication that the relief valve acoustic response occurred at or below 100% CLTP. Thus, by default, this review could not rule out the possibility that it would be encountered at EPU conditions, and accordingly, an extrapolation of the low, CLTP loads (which do not have any SRV acoustic resonance) may under predict the EPU loads.
- The experience gained to date on FEM analysis demonstrates that the resulting stresses are dependent not only on the magnitude of the loading, but also on the frequency. Although present computational methodologies require in plant measurements at EPU to calculate the actual magnitude of relief valve acoustic resonance, available analytical techniques allow calculating the frequency beforehand. This analytical technique can model the complex relief valve standpipe configuration, with various changes in diameter and protrusions (e.g., stems) in the chamber path, to provide a more accurate prediction than achieved solely by inputting the chamber height.
- Available literature shows that the MSL velocity at the onset, peak, and the end of the resonance of the vortex and acoustic frequencies for a standpipe is

predictable provided that there is accurate information on the branch line configuration (e.g., branch line diameter, main line diameter, and branch line acoustic frequency). Knowing the velocities for the onset and peak resonance allows determination of if and when the phenomenon will be encountered.

Thus, in order to provide a more meaningful EPU steam dryer analysis prior to EPU power ascension, PSEG will undertake a program with the objectives of (1) determining the HCGS relief valve branch line acoustic frequency and (2) estimating the reactor power at which the onset and peak relief valve branch line resonance occurs. These are discussed in further detail below.

HCGS Relief Valve Branch Line Acoustic Frequency

HCGS has a total of fourteen (14) relief valves on the MSLs. As opposed to earlier plants, the HCGS design has only one type of relief valve. This is the Target Rock 7567F design which combines the function of a safety relief valve (SRV) to prevent overpressurization and a power operated relief valve to provide controlled depressurization and cooldown.

Two MS lines have 4 valves each; two MS lines have 3 valves each. PSEG has collected the required information for detailed analytical modeling of this branch line. The relief valve branch line and relief valve configuration, including heights, are identical at all 14 locations. The configuration is a 26-inch to 8-inch sweepolet fitting, an 8-inch nominal diameter schedule 160 pipe stub, and a flange that bolts up the bottom of the relief valve. The flange serves a second function. The inside diameter (ID) is tapered to transition from the 6.8-inch ID of the 8-inch pipe down to 5.2-inch at the entrance of the SRV. The ID on the inlet of the relief valve is 6.0-inches.

HCGS will determine by a detailed calculation the relief valve branch line one-quarter wave acoustic frequency. This is expected to be different from the calculated frequency based on chamber height alone since the internal geometry of the relief valve stub chamber is not a simple cylinder. The higher acoustic modes will also be determined, but they are unlikely to be a concern since they are much higher than any anticipated vortex shedding frequency.

Although this first objective is an input into the second objective, it is also a key piece of information. When this relief valve acoustic frequency is identified with reasonable assurances, the HCGS FEM will be rerun to determine the maximum loading that the steam dryer can tolerate at that frequency. This will also include reviews for plus and minus 10% variation in frequency. This will be done even if the second objective determines that it is unlikely that the uprated flow conditions will cause resonance of the vortexing and acoustic frequencies in the relief valve standpipe.

Relief Valve Branch Line Resonance of Vortexing and Acoustic Frequencies

Reference 5 shows that the dimensionless Strouhal number can be used to predict the MSL velocity range that causes the vortexing frequency and the acoustic frequency to resonate for a specific branch line configuration. Since power is a direct correlation to MSL steam velocity, the potential to encounter relief valve branch line acoustic loads between CLTP and EPU can be determined. In its simplest relationship:

MS Velocity = (branch line ID) x (branch line first acoustic mode) / Strouhal #

Reference 5 summarized experience collected from over 40 valves to determine that the onset of resonance would always be avoided if the Strouhal number were kept above 0.60. However, subsequent testing provided better information. Reference 11 tested three branch line diameter (d) to the main line diameter (D) configurations. This testing showed that the d/D ratio had a significant impact on the onset of resonance. For d/D of 0.57 there was agreement with the Reference 5. For d/D of 0.25, more representative of HCGS, onset of resonance would not be expected until the Strouhal number decreases below 0.50, and would not peak until the Strouhal number was ~ 0.40. Thus for HCGS:

MS velocity at onset of resonance = 2 x branch line ID x first acoustic mode

MS velocity at peak resonance = 2.5 x branch line ID x first acoustic modeRather than relying solely on the above information, HCGS is investigating scale testing of the HCGS relief valve branch line to allow improved predictions of the MS velocity that results in the onset of resonance. If undertaken, this would be scale testing only of flow under the relief valve branch line. It would not replicate the MS system, reactor dome, or steam dryer.

<u>EPU Uncertainty Discussion</u>

The CLTP uncertainty evaluation only considered uncertainties that resulted in penalties to determine that the calculated CLTP stresses should be increased by a factor of 1.43. The steam dryer still retained a 2.6 margin.

In order to demonstrate additional margin for increased loading at EPU, PSEG is reviewing options to reduce the uncertainty on the strain gage input during the EPU power ascension testing. This includes both the location and arrangement along the circumference. The location in the MS tunnel adds a 42% uncertainty penalty. The single strain gage location along the circumference, based on Quad Cities data, is on an average 1.7 higher than the value predicted by the average of four strain gages spaced at 90° intervals.

Although relocating the strain gage locations into the drywell is known to reduce the uncertainties, this must be balanced against the radiation dose to perform this work and justified by demonstrating that increased margins will be required for EPU.

Accordingly, the decision on strain gage locations for EPU power ascension will be made after (1) a level of confidence is establish on whether or not the relief valve acoustic loading will be present at EPU conditions (2) the FEM is rerun to determine the steam dryer's tolerance to loads at the relief valve acoustic frequency, and (3) other options are evaluated.

Steam Dryer EPU Modifications

Due to the modifications done prior to initial operation to reinforce the steam dryer at all known weak points and the margins demonstrated at CLTP loadings, no modifications are anticipated. However, PSEG will review this after the relief valve acoustic frequency is calculated, the steam dryer FEM identifies if any areas are susceptible to this frequency, and a level of confidence establish as to whether or not EPU operation will enter the onset of resonance at this frequency.

Computational Fluid Dynamics Model

HCGS has employed Fluent Incorporated to develop a hydrodynamic loads model of the HCGS steam dryer utilizing computational fluid dynamics (CFD). This methodology relies upon first principles and very fine computational detail to generate a model of the fluid flow within the reactor steam dome. This model complements the ACM.

The CFD model utilizes a detailed model of the HCGS steam dryer, the reactor pressure vessel steam dome area down to the normal water level, and the details of the main steam nozzles. Saturated steam flow through the dryer will be modeled at CLTP and the licensed power uprate (3840 MWt). The CFD model has been completed and computer runs have commenced.

PSEG will review the results from the CFD analyses to determine if there are any significant changes in the flow patterns due to operation at the higher power. However, it is anticipated that the loadings will be small in all areas except near the outer hood banks. This expectation is drawn from the curved hood design and the relatively large steam dome area afforded by the 251-inch diameter reactor pressure vessel. The only area of high steam velocity in the reactor dome is at the inlet to the MS nozzles. Fortunately, this area is directly opposite the most robust part of the HCGS steam dryer, the outer hood. The outer hood consists of 0.5-inch bent plates welded to 0.375-inch end plates and 0.375-inch cover plate. As opposed to retrofitted square hood designs, this area on a curved hood dryer is free of any external gusset plates since it relies solely on support plates on the inside of the hoods. The FEM results show that the most limiting component in the outer hood of the steam dryer facing the MS nozzles has considerable design margin and low fatigue stresses.

The loadings for the outer hood area will be provided by Fluent to PSEG. PSEG will determine how to superimpose the CFD load with the load calculated by the ACM.

However, it is judged that these loads will be easily accommodated by the large margin available for the HCGS curved hood design.

EPU Power Ascension and Acceptance Criteria

By May 2006, PSEG anticipates (1) finalizing the analyses to determine the SRV acoustic frequency and to estimate the power level corresponding to the onset and maximum resonance for the relief valve branch lines and (2) revisions to the FEM to identify the steam dryer's tolerance to loads at the relief valve acoustic frequency. Small scale testing to confirm analytical predictions for the power corresponding to the onset and maximum resonance may occur late 2006.

PSEG will develop a power ascension test plan that incorporates predetermined hold points to allow for review and confirmation of dryer loads. A correlation will be developed between the dynamic pressure information obtained from the strain gages and the steam dryer stresses. At each hold point, the strain gages will be read to develop the dynamic pressure for that power. This data will be trended as well as compared to the predetermined acceptance criteria for the steam dryer. If relief valve acoustic resonance is detected, the magnitude at each hold point will be determined and compared against the specific load limit for that frequency. Similarly, if any significant load at a discrete frequency is detected, it will be reviewed for acceptability.

PSEG will establish procedures as part of the power ascension test plan to address any unacceptable results. These procedures will provide guidance for additional evaluations or power reductions as necessary.

At the completion of power ascension, PSEG will document the loads calculated from the MSL strain gage measurements and, through a FEM run, document the steam dryer acceptability at EPU conditions. This "as-left" steam dryer documentation will be an input in the steam dryer inspections for FIV fatigue damage.

Reactor Steam Dryer Instrumentation

Based upon the reinforced (prior to commercial operation) curved hood design of the dryer, CLTP results, nominal main steam velocities, and preliminary estimates on the onset conditions for relief valve acoustic resonance, PSEG believes the likelihood of high EPU loading on the HCGS dryer is minimal.

The results of the benchmarking at Quad Cities 2 validate that the ACM methodology can provide accurate results. And consequently, the primary concern on the overall accuracy of the ACM loads for HCGS lies with limiting the uncertainty of the input to the ACM model, the strain gage readings.

PSEG is committed to showing that the steam dryer margins will bound any EPU measured loads including all uncertainties. PSEG is reviewing the options for

demonstrating improved strain gage accuracy. At the same time PSEG will continue to use the FEM to identify any potential areas of weaknesses at the relief valve acoustic resonance and to improve margins, if appropriate, by using higher dampening values.

In the unlikely eventuality that PSEG cannot demonstrate that the margins bound uncertainties, PSEG will consider options to instrument the HCGS steam dryer prior to uprated operation, with sufficient instrumentation to confirm stress levels. Therefore, by analytical or physical methods, PSEG intends to monitor the dryer loads during power ascension to verify that the steam dryer is not subjected to FIV fatigue stresses that could cause failures.

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HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
FLOW INDUCED VIBRATION

This Attachment summarizes actions completed or currently planned to address the potential for increased flow-induced vibration (FIV) during operation at CPPU conditions.

Introduction

Increased flow rates and flow velocities during operation at CPPU conditions are expected to produce increased FIV levels in some systems. While a review of industry EPU operating experience identified very few component failures that can be attributed to EPU, most of these failures were related to FIV.

In November 2004, the BWR Owners Group issued NEDO-33159, Revision 0, "Extended Power Uprate (EPU) Lessons Learned and Recommendations" based on operating experience (OE) and evaluations from BWR plants that have previously implemented EPUs and from plants currently performing pre-EPU evaluations.

During Hope Creek's RF012 refueling outage a vibration monitoring program was implemented to support the PSEG Extended Power Uprate Project. Piping systems both inside and outside the drywell are being monitored using temporary accelerometers. Monitoring occurs inside the drywell (room 4220), turbine building steam tunnel (room 1405/3491), and in feedwater heater room 1504. The following piping is being monitored for vibration to establish baseline data prior to uprate and to ensure that the vibration levels of the selected piping systems are within acceptable limits for those operating conditions anticipated during service:

- Main Steam (Drywell And Turbine Building)
- Feedwater (Drywell And Turbine Building)
- Main Steam Relief Valve Discharge Piping ("J" & "P " Valves Discharge Piping)
- RCIC Steam Supply (Inside Drywell),
- Reactor Recirculation (And RHR Inside Drywell, And Their Associated Valves And Attached Piping)
- Reactor Recirculation Small Bore Piping
- Extraction Steam

In addition, twenty strain gages were installed on four Main Steam pipes (in the turbine building) to measure the amount of bending on the pipe and the acoustic wave pressure pulsations, thought by the industry, to be a major contributor to the steam dryer damage that has occurred at EPU power levels in several plants.

Drywell Monitoring Information

The Main Steam, and Feedwater systems are to be monitored because of their significant increases in flow to achieve increases in thermal power. In addition to these systems, the Recirculation/RHR system inside the drywell will be monitored due to past and present plant vibration issues. Some small bore piping attached to recirculation and RHR will also be monitored.

Recirculation system vibration levels have previously been correlated to specific recirculation pump speeds. Operating Procedures have been revised to limit system operation at those pump speeds. Work performed within several previous DCPs implemented for the small bore recirculation piping included the addition of tie-back supports to minimize differential pipe movement, and the addition of strain gages and accelerometers to monitor pipe motion. Although the increase in Recirculation flow due to the Extended Power Uprate is considered negligible, the Recirculation large bore, and connected RHR piping will be included in the Flow Induced Vibration monitoring to ensure that small variations in system flow do not produce unacceptable levels of vibration.

The RCIC Steam Supply (inside drywell) and Main Steam Relief Valves (MSRV) "P" & "J" discharge piping were chosen to be monitored, because they are branch piping connections of the Main Steam System. OEs concerning branch lines and connected piping systems to MS and FW were considered in making the decision to instrument these lines.

The current scope monitors approximately 34 locations using 90 accelerometers and 3 proximity probes in the drywell (see Appendix A for locations). A modal analysis was performed on the as-modeled piping system to determine natural frequencies and mode shapes. The sensor (accelerometer) locations were determined based on a review of the mode shapes. The accelerometer locations correspond to node points with high-calculated modal displacements. Other factors used to determine accelerometer locations were; installation accessibility including ALARA concerns, minimizing the impact to insulation, and redundancy of accelerometers. Some recirculation piping accelerometer locations were selected based on previous evaluations and vibration issues that have occurred on this system. In addition, both recirculation loops are monitored at similar locations to aid in comparisons between the two loops.

Turbine Building Monitoring Information

Twenty-four accelerometers at ten locations are being monitored in the turbine building (see Appendix A for locations). Main Steam, Feedwater, and Extraction Steam are monitored at 9 total locations in the turbine building steam tunnel rooms 1405 / 3491. One location is monitored in Feedwater Heater Room 1504.

Similar to the drywell accelerometers, the locations and number of accelerometers in the turbine building were determined based on performing a modal analysis of the main steam, feedwater, and extraction steam piping system.

Due to the similar piping routing of the four main steam lines, only two of the four are monitored. Between the two monitored main steam lines, at least two accelerometers are used to monitor each direction. The feedwater line does not have the same amount of redundancy in the X and Z-directions; this is due to the low expected dynamic response of the piping system in these directions. The configuration of the extraction steam system is not symmetric so additional locations were selected to be able to capture the dynamic response of the piping system.

Steam dryers failures have occurred previously, attributed to loads associated with increases in steam flow after implementation of Extended Power Uprate (EPU). Acoustic loads (pressure pulsations) are thought by the industry to be a major contributor to the steam dryer damage that has occurred at EPU power levels in some plants. To help facilitate the determination of these loads on the steam dryer due to acoustic phenomena (pressure pulsations) in the main steam lines, strain gages were installed on each of the four main steam lines. The four Main Steam lines have twenty strain gages with protective covers installed (see Appendix B for locations). Two strain gages are installed in the hoop direction at eight locations on the main steam lines, two locations on each main steam line. In addition, two strain gages are installed in the longitudinal direction at two locations to measure the amount of bending on the pipe.

Data from the strain gages on the Turbine Building Main Steam piping will be used in models that predict dynamic pressure loading on the steam dryer. The methods used, model theory and other details are contained in Attachment 7.

<u>Acceptance Criteria</u>

For piping vibration testing, the acceptance criteria are associated with the allowable design alternating (vibration) stress levels. The steady state flow induced vibration (FIV) maximum stress levels of the Main Steam Line (MSL) and Feedwater (FW) piping must remain below the endurance limit of the piping material. This is because many cycles of vibration will be encountered over the remaining design life of the plant. The ASME design fatigue endurance limit for steady state alternating stresses from vibration is 10,880 psi (zero to peak) for austenitic (stainless) steel piping materials. The design fatigue endurance limit for steady state alternating stresses from vibration is 7,690 psi (zero to peak) for carbon steel piping materials. These fatigue design endurance limits were taken from ASME Pressure Vessel and Piping Code, Section III, Division 1 – Appendix I, Figure I-9.2.2, 1989 and the American National Standard, OM S/G 1997, "Requirements for Preoperational and Initial Startup Vibration Testing of Nuclear Power Plant Piping."

As far as evaluation of branch lines is concerned, it is noted that typically the measured piping vibration levels of the MS and FW piping are only a few percent of these criteria. Hence, the vibration levels of the large bore piping are small and therefore the vibration levels of components and branch piping attached to the large bore piping are not of concern. However, if during testing, the vibration levels of the large bore MS and FW piping are found to be significant, then the attached components and branch piping connections will have a higher probability of fatigue failure relative to operation at the

original power level. Hence when the measured MSL or FW large bore piping vibration levels reach a significant fraction of their acceptance criteria, the attached branch piping connections will be further evaluated.

Preliminary Results

Data was taken with the three acquisition systems during power ascension immediately following the RF12 Refueling Outage at multiple power levels and recirculation pump speeds.

The discussion below is based upon preliminary analysis of this data. PSEG will continue to collect and analyze vibration data at CLTP levels as baseline information for EPU power ascension. As more data is collected and analyzed, PSEG will refine the results presented below. In particular, the recirculation data collected to date does not represent the complete range of recirculation pump speeds. HCGS is licensed for increased core flow to approximately 105 percent of original. The data collected to date only includes pump speeds to approximately 100 percent of original rated core flow.

The measured vibration levels at Hope Creek are less than the acceptance criteria, thus, the vibration levels are acceptable. The analysis results show that the vibration levels steadily increased throughout power ascension, but remained at an overall low level when compared to the allowable values. The maximum steady state vibration stresses in the main steam, feedwater, and extraction steam piping systems are below the stress criteria of 7,692 psi. The maximum stresses for the reactor recirculation system are less than 7,692 psi for the carbon steel portions and less than 10,880 psi for the stainless steel portions. The preliminary vibration data indicates that flow induced vibration in the main steam and feedwater systems is low relative to pre-EPU levels at other plants.

Current vibration data indicates that dominant vibration frequencies (the frequencies that generate maximum displacements and accelerations) correspond to multiples of recirculation pump speed. For the examples referenced below, the recirculation pump speed was 1482 rpm (24.7 Hz). Every accelerometer with reliable signals on the Main Steam and Feedwater systems measured peak accelerations at 123.5 Hz (5 times 24.7 Hz). HCGS utilizes five vane recirculation pumps. Therefore, it is presumed that recirculation system effects are the dominant contributor to measured vibration levels in these two systems. A frequency vs. acceleration chart from the feedwater system that shows the maximum recorded acceleration from the feedwater and main steam systems is provided in Figure 1.

Piping and component vibration levels of the recirculation system are approximately an order of magnitude higher than the main steam and feedwater systems. Again, the peak accelerations and displacements occur at multiples of the recirculation pump speed.

As expected, the large bore recirculation piping vibration levels on average are approximately five times that of the average main steam and feedwater system vibration

levels. A typical acceleration chart from the recirculation system large bore piping is shown in figure 2.

As the recirculation system will experience insignificant changes in operating parameters at EPU conditions, the results above are considered representative of the recirculation system under EPU conditions. HCGS is planning to replace the B-recirculation pump during the next refueling outage (RF-13).

PSEG is monitoring piping vibration in preparation for power uprate. Flow induced vibration in the main steam and feedwater systems compares favorably with vibration levels in other plants. During the power ascension to uprated power levels, PSEG will continue to monitor vibration levels to verify that they remain within acceptable limits. The HCGS EPU power ascension test program will establish hold points and acceptance criteria to ensure the vibration monitoring is effective in preventing undesirable flow induced vibration conditions.

<u>Reactor Recirculation System Piping Vibration</u>
The reactor recirculation pumps are driven by variable speed motors, having a rated speed of 1680 rpm. However, when the pump speed is about 1529 rpm, increased levels of containment noise have been observed. Consequently, pump speed is currently limited by procedure to 1510 rpm, which produces a core flow of approximately 100 Mlb/hr at the current licensed thermal power.

To regain core operating flexibility for the EPU condition, PSEG is taking steps to resolve the containment noise and vibration issues to permit the reactor recirculation system to be operated over its full range (up to 105 Mlb/hr core flow).

PSEG's plans to resolve containment noise and vibration issues include:

- Development of an analytical model of the recirculation piping including acoustic effects that will predict piping response for pump speeds above 1510 rpm
- Benchmarking the model using piping acceleration data collected from accelerometers currently installed on the reactor recircirculation and attached piping
- Development of an evolution plan for recirculation pump operation at speeds greater than the current administrative limits
- Data collection, model benchmarking and verification of system acceptability for recirculation pump operation at speeds greater than the current administrative limits
- Implementation of required procedure and configuration changes

PSEG currently plans to complete actions to resolve the containment noise and vibration issues and to restore the full range of recirculation system flow control for plant restart after the refueling outage scheduled for Spring 2006.

Additional FIV Program Actions

Industry Operating Experience (OE) has been reviewed for applicability to the uprated conditions. As part of the EPU implementation plan, OE attributed to FIV will continue to be reviewed. When determined applicable, they will be dispositioned to be addressed as part of the EPU implementation. BWROG recommendations for vibration monitoring and evaluation will be reviewed and incorporated into the EPU vibration monitoring program as appropriate.

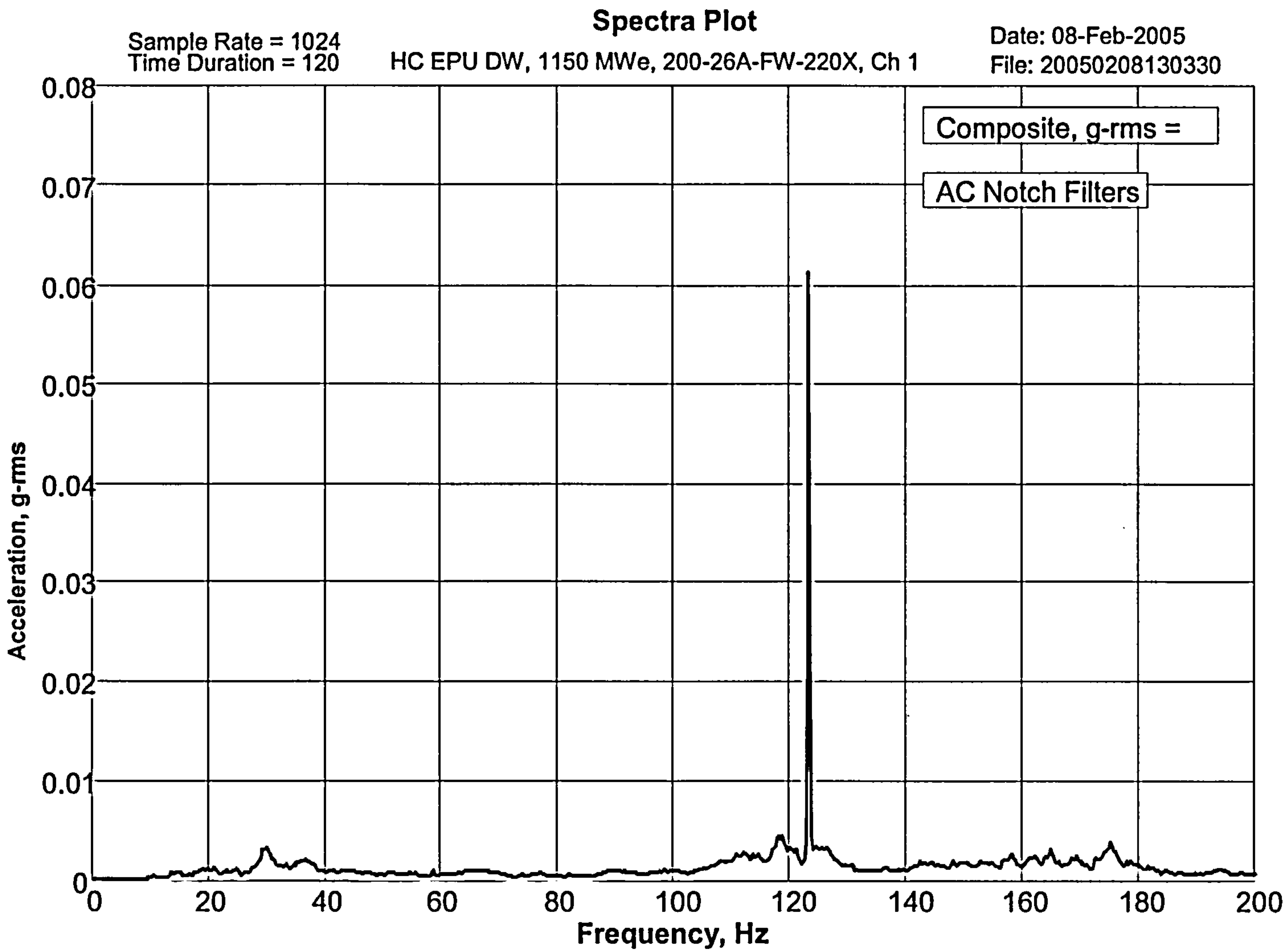

Figure 1: Maximum vibration level noted at 100% RTP (feedwater 12" branch) Note 123.5 Hz peak

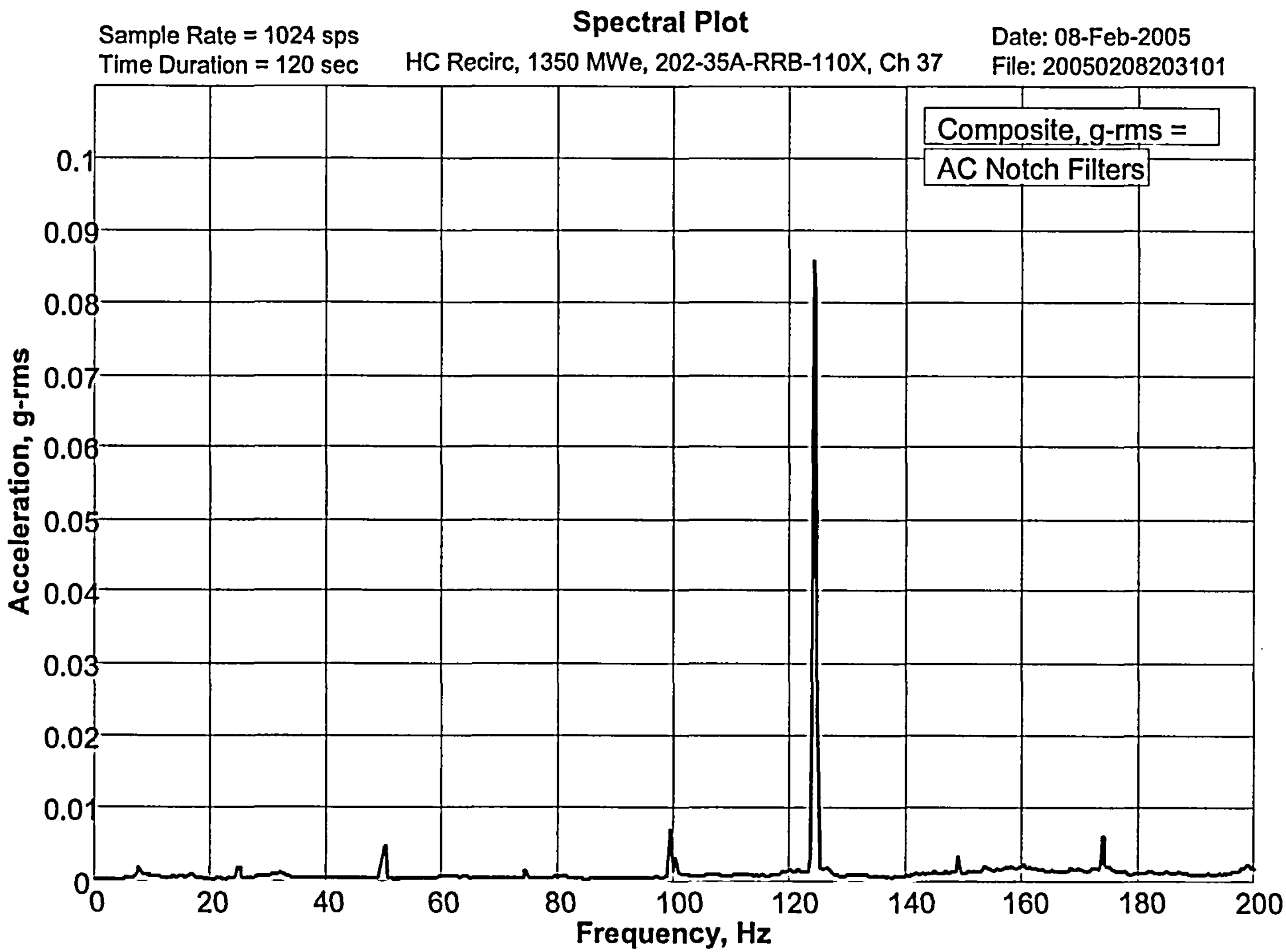

Figure 2: Typical recirculation system vibration chart. (22" recirculation B - ring header)

Appendix A
Accelerometer Locations

1. **Main Steam inside the Drywell**
   a. M/S line A, between inboard MSIV and drywell penetration (node 081)
   Accelerometers in x and y

   b. M/S line A, on vertical run after first elbow outside of RPV (node 014)
   Accelerometers in x and z

   c. 4" RCIC outlet line near 26" M/S line A (node 430) - Main Steam Branch connection
   Accelerometers in y and z

   d. M/S line A, on SRV "J" line (node 022j)
   Accelerometers in x and z

   e. M/S line B, on vertical run before last elbow before inboard MSIV (node 534)
   Accelerometers in x and y

   f. M/S line B, between SRV "K" and SRV "B" (node 490)
   Accelerometers in y and z

   g. M/S line B, on vertical run after first elbow outside of RPV (node 460)
   Accelerometers in x, y and z

   h. M/S line B, on SRV "P" line (node 040p)
   Accelerometers in x, y and z

2. **Feedwater inside the Drywell**
   a. 12" FW line B, N4C branch just past the reducer after the N4B branch (node 160)
   Accelerometers in x and y

   b. 12" FW line B, N4C branch just past the elbow after the N4B branch (node z002)
   Accelerometers in x, y and z

   c. 12" FW line B, N4B branch 27 inches past the reducer after the N4A branch (node 280)
   Accelerometers in x and z

   d. 12" FW line B, N4A branch on the upward sloping section (node 220)
   Accelerometers in x and y

   e. 24" FW line B, prior to N4A branch (node 50)
   Accelerometers in x, y and z

3. **Reactor Recirculation (RR) inside the Drywell**
    a. 12" Jet Pump Riser N2H (270 degrees), below elbow at N2H (this riser is an extension of the 22 inch outlet line from the "A" RR pump) (node 323)
    Accelerometers in x, y and z

    b. 28" "A" RR suction line between elbow and isolation valve (node 14)
    Accelerometers in x, y and z

    c. 12" RHR return line between elbow and recirc "A" riser (node 602) – RR branch connection
    Accelerometers in x, y and z

    d. 12" Jet Pump Riser N2C (090 degrees), below elbow at N2C (this riser is an extension of the 22 inch outlet line from the "B" RR pump) (node 323)
    Accelerometers in x, y and z

    e. 28" "B" RR suction line between elbow and isolation valve (node 13)
    Accelerometers in x, y and z

    f. 22" RR "A" ring header between N2J and N2K risers (node 110)
    Accelerometers in x, y and z

    g. 22" RR "B" ring header between N2E riser and end of ring header (node 110)
    Accelerometers in x, y and z

    h. 12" RHR return to RR "A" between isolation and check valves (node 621)) - RR branch connection
    Accelerometers in x, y and z

    i. 12" RHR return to RR "B" downstream of F060B isolation valve (node 614)) - RR branch connection
    Accelerometers in x, y and z

    j. 12" RHR return to RR "B" between elbow and recirc riser "B" (node 603F) - RR branch connection
    Accelerometers in x, y and z

    k. 20" RHR suction off of "B" RR suction line between third and fourth elbows (node 515n)) - RR branch connection
    Accelerometers in x, y and z

    l. 1" RHR shutdown cooling supply vent line no. BC-196-DBA-1" Between valve V409 and end cap (node 196)) - RR branch connection
    Accelerometers in y and z

m. 1" "B" RR sensing line no. BB-224-CCA-1" for flow measurement. Located above connection to RR 28" pipe. (node 155/160)
Accelerometers in x and z

n. 1" "A" RR pump discharge pressure sensing line no. BB-226-CCA-1 (node 130)
Accelerometers in x , y and z

o. 1" RHR FO50A bypass line no. BC-121-DBA-1". Either side of 2nd elbow from upstream branch connection. (node 097) - RR branch connection
Two accelerometers in z

p. "B" RR pump motor
Accelerometers in x, y and z on top of motor
Accelerometers in x and z on base of motor

q. RHR 20" line Isolation valve FO77 limit switch stem protector end cap - RR branch connection
Accelerometers in x, y and z
Proximity Probe

r. RHR 12" line Isolation valve FO60B limit switch stem protector end cap. - RR branch connection
Accelerometers in x, y and z
Proximity Probe

s. Valve F060A (node 706)
Accelerometers in x, y and z
Proximity probe

t. Valve F050A
Accelerometers in x and z

4. Main Steam inside the Turbine Building

a. 28" M/S "A" between outboard MSIV and equalizing header (node z013)
Accelerometers in x and y

b. 28" M/S "A" between equalizing header and turbine stop valves (node z018)
Accelerometers in x, y and z

c. 28" M/S "B" between outboard MSIV and equalizing header (node z003)
Accelerometers in x and y

d. 28" M/S "B" between equalizing header and turbine stop valves (node z008)
Accelerometers in x, y and z

5. **Feedwater inside the Turbine Building**
   a. 24" Feedwater "A"3.3 feet downstream from hanger AE-013-H62 (node 817)
   Accelerometers in y and z

   b. 24" Feedwater "A" 24 feet upstream from header (node 731)
   Accelerometers in x and y

6. **Extraction Steam inside the Turbine Building**
   a. 14" extraction steam line on the horizontal run prior to elbow and riser to FW heater 6C (node z008)
   Accelerometers in x, y and z

   b. 14" extraction steam line on the horizontal run prior to 2nd elbow and riser to FW heater 6A (node 046)
   Accelerometers in x and y

   c. 14" extraction steam line on the horizontal run just past 3rd elbow prior to riser to FW heater 6B (node 230g)
   Accelerometers in x and y

   d. 14" extraction steam line on the horizontal run 35 feet prior to 3rd elbow prior to riser to FW heater 6B (node z010)
   Accelerometers in x, y and z

Appendix B
Strain Gage Locations

1. <u>Main Steam (MS) inside the Turbine Building</u>

   a. 28" MS "A" just downstream of the outboard MSIV (node 233/234
      i. 2 strain gages radially oriented
      ii. 2 strain gages longitudinally oriented

   b. 28" MS "A" near the equalizing header (node 237/238)
      i. 2 strain gages radially oriented

   c. 28" MS "B" just downstream of the outboard MSIV (node 062/64)
      i. 2 strain gages radially oriented
      ii. 2 strain gages longitudinally oriented

   d. 28" MS "B" near the equalizing header (node 067/068)
      i. 2 strain gages radially oriented

   e. 28" MS "C" just downstream of the outboard MSIV (node 582/584)
      i. 2 strain gages radially oriented

   f. 28" MS "C" near the equalizing header (node 587/588)
      i. 2 strain gages radially oriented

   g. 28" MS "D" just downstream of the outboard MSIV (node 402/404)
      i. 2 strain gages radially oriented

   h. 28" MS "D" near the equalizing header (node 407/408)
      i. 2 strain gages radially oriented

HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
SUMMARY OF GRID IMPACT STUDIES

INTRODUCTION

The PJM Interconnection (PJM) is the Regional Transmission Organization (RTO) responsible for operation of the transmission grid. PJM performed studies to evaluate the effect of the Hope Creek EPU operation on transmission system grid stability and capability. The PJM studies also incorporated increases in electrical output from Salem Units 1 and 2 and the installation of an additional circuit breaker in the Hope Creek 500 kV switchyard. The proposed HC EPU electrical power output is 1320 MWe. The results of the PJM studies are documented in the Artificial Island Operating Guide (AIOG) (PSEG Engineering Evaluation A-5-500-EEE-1686) which controls the MW and MVAR operating curves specified by the PJM Interconnection for Salem and Hope Creek.

ELECTRICAL SYSTEM GENERAL DESCRIPTION

Artificial Island is composed of three nuclear units connected to the PJM 500 kV power system. Salem Unit 1 (1300 MVA), Salem Unit 2 (1300 MVA) and Hope Creek (1373 MVA) supply power to the 500 kV system through five transmission lines:

- 5015 Hope Creek – Red Lion
- 5021 Salem – East Windsor
- 5024 Salem – New Freedom
- 5023 Hope Creek – New Freedom
- 5037 Salem – Hope Creek

Figure 1 shows the Artificial Island Offsite Electrical System One Line Diagram. Two lines (5015 and 5021) are interconnected directly to the 500 kV power system. These lines are most critical in maintaining system stability at Artificial Island. The New Freedom lines are connected to three 500/230 kV autotransformers and the Salem – Hope Creek serves as a tie line between the two stations.

Before modification, a fault on the Hope Creek - Red Lion (5015) line coupled with a breaker failure would have tripped the Salem - Hope Creek tie line. With the addition of a new 500 kV circuit breaker (breaker 2-4 in Figure 1) in 2004, this possibility has been eliminated.

The design basis for the electric power system is described in Section 8.0 "Electric Power" of the Updated Safety Analysis Report (UFSAR).

The bulk power transmission system at Hope Creek Generating Station (HCGS) operates nominally at 500-kV. The station supplies power to the 500 kV system through three single-phase power transformers. These transformers step the voltage up from 24 to 500 kV. The offsite power for the plant is fed through the 500 kV system via the 13.8-kV yard.

Three independent offsite power sources supply the Hope Creek plant. One source is the Salem-Hope Creek 500-kV line. This line feeds the 500/13.8-kV yard via 500 kV main bus section 2. The other sources are a 22.1-mile tie to the Red Lion Switching Station, located northwest of Hope Creek near Newark, Delaware, which feeds section 3 of the 500-kV bus, and a 42.9-mile tie to the New Freedom Switching Station, located northeast of Hope Creek in Camden County, New Jersey, which feeds section 5 of the bus. Red Lion and New Freedom are 500/230-kV switching stations approximately 40 miles apart.

Transmission lines meet or exceed design requirements set forth by the National Electrical Safety Code and agree with Lower Delaware Valley 500-kV Transmission Design Criteria. Lines meet the Army Corps of Engineers requirements for clearance over flood levels. All bulk power transmission lines are designed to withstand 100 mph wind loads on bare conductors. The transmission network provided for the Hope Creek plant complies with General Design Criteria (GDC) 17 and 18 of Appendix A to 10CFRPart 50.

IMPACT STUDIES

The PSE&G bulk power system is planned in accordance with Mid-Atlantic Area Council (MAAC) Reliability Principles and Standards. MAAC is one of ten regional reliability councils of the North American Electric Reliability Council (NERC). The studies performed for Salem and Hope Creek evaluated the compliance of the planned system with the MAAC Reliability Principles and Standards. The studies included two major portions: 1) power flow analysis and 2) stability analysis.

The power flow portion of the analysis consisted of evaluating the planned system under normal and emergency operation conditions. The transmission system was tested under normal conditions in order to assess the transmission network element loading with the addition of the proposed upgrades previously described. Testing included simulations of heavy power transfer conditions followed by single and multiple transmission facility outages.

The stability analysis was conducted using the PSS/E Load Flow and Dynamic Stability software provided by Power Technologies Incorporated.

The types of faults evaluated in accordance with the MAAC Criteria, Section IV, were:

1. Three phase faults with normal clearing time

2. Single phase to ground faults with breaker failure (delayed clearing).

Faults on transmission lines around Artificial Island are more critical for system stability than tripping either of the nuclear units. Therefore, the system study considered the most critical line faults consistent with MAAC criteria.

The analysis established that the critical fault condition was a three-phase fault on the Hope Creek – Red lion 500 kV line (5015) at Hope Creek. The single phase to ground fault case with delayed clearing simulated a stuck breaker condition, such that the breaker closest to the fault on the faulted phase failed to open. Therefore, backup or delayed clearing time is required to isolate the fault.

Minimum gross MVARS limitations required on the generators when specific 500kV lines are out of service can cause 500 kV voltage criteria deviations in both real time and post contingency. If this occurs, options to correct the deviation include a generation reduction at the Artificial Island, which may be required to allow MVAR reduction to relieve the voltage violation. The stability curves in the Artificial Island Operating Guide (AIOG) will be used to determine the MW reduction required.

The AIOG provides information concerning the maximum gross MWs and MVARs output for each of the Artificial Island units, to maintain a stable grid operation under various system conditions. These conditions include, operation with one, two and three units in service and various transmission line and Hope Creek 500 kV breaker outages. The AIOG is provided by PJM and is used by PSEG Electric System Operation Center as well as Salem 1, Salem 2 and Hope Creek Control Rooms to operate the units at Artificial Island.

The results and curves contained in the AIOG are obtained from computer simulations using the PSS/E software. The studies are done using the MAAC Reliability Principles and Standards.

ASSUMPTIONS AND CRITERIA

When dispatching power flow and determining stability limits, the pre-fault steady state voltages at selected 500 kV buses are assumed to be between 1.1 pu and 1.0 pu. The pre-fault terminal bus voltages at Salem Units 1 and 2 and Hope Creek shall not be below 0.9 pu.

The PJM transient stability criteria require that the system must be stable for all faults considered and that the post-fault transient voltages at 500 kV buses shall not be below 0.7 pu.

CONCLUSIONS

The studies described demonstrated that with the installation of the additional circuit breaker in the Hope Creek 500 kV switchyard:

1. The power system is stable for all three-phase and single-phase faults studied, when cleared by relay protection in accordance with planned settings,
2. Under all power flow conditions tested, the stations and the transmission system satisfy the MAAC Reliability Principles and Standards,
3. Faults on transmission lines around Artificial Island are more critical for system stability than tripping either of the nuclear units. Tripping of the Hope Creek unit will not have detrimental effects on grid stability,
4. The Artificial Island bus stability and continued availability was confirmed.

In summary, PSEG concludes that the effects of the proposed Hope Creek EPU on the offsite electrical power system will not affect the ability to meet the requirements of GDC 17. The Hope Creek unit remains stable, provided that it is operated within the limits specified in the AIOG.

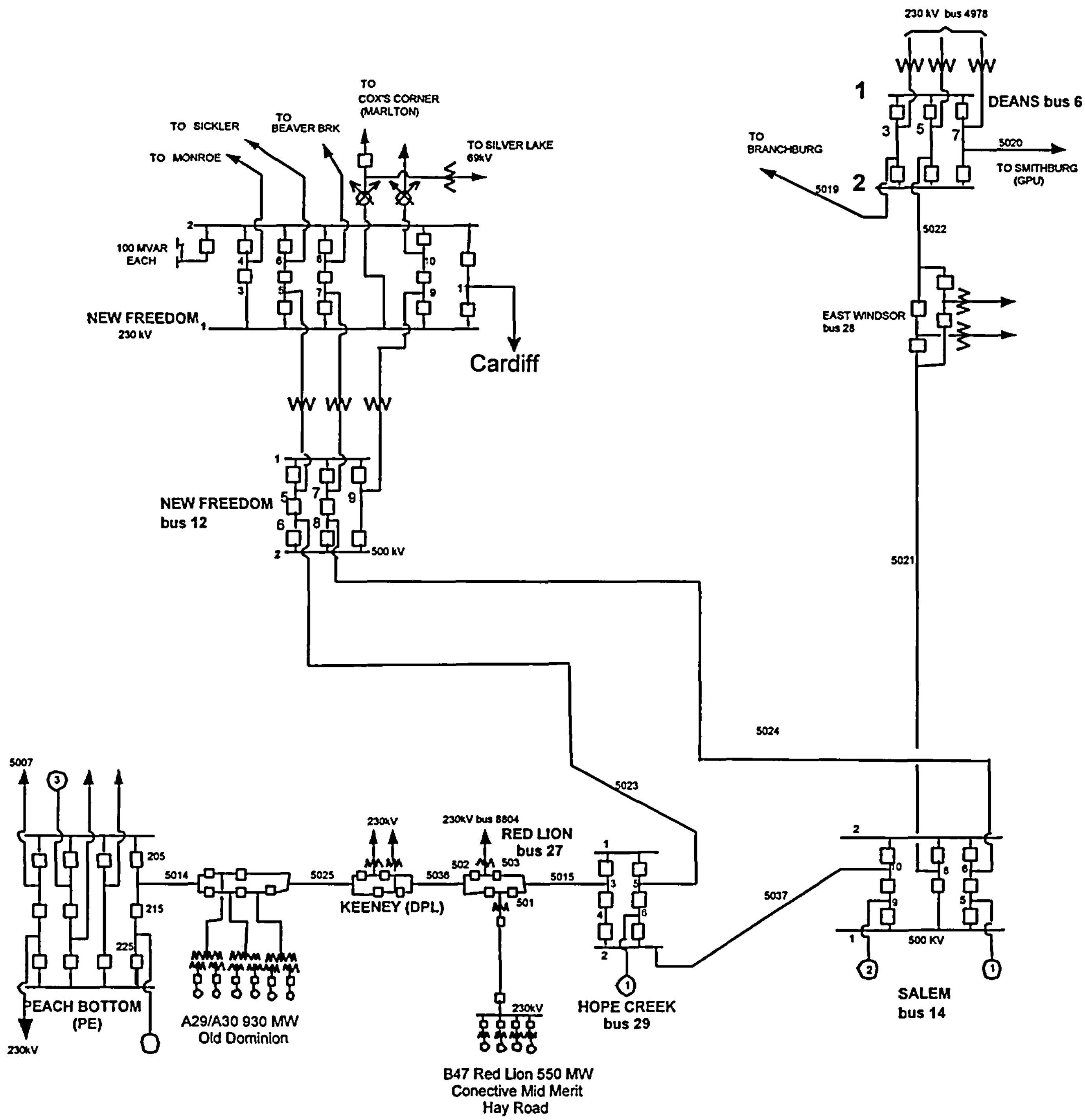

Figure 1
Artificial Island Offsite Electrical System One Line Diagram

HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
REVIEW STANDARD MATRICES

This Attachment cross-references the areas of review in NRC Review Standard RS-001 with the information in the Hope Creek PUSAR, the NRC approved CLTR for constant pressure power uprate, and other documents submitted in support of this request. Notes have been added to the matrices to provide additional guidance to direct the reviewers to the specific safety analyses and conclusions. The notes also provide references to the applicable supplemental reports for fuel related topic areas.

MATRIX 1

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Materials and Chemical Engineering

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Reactor Vessel Material Surveillance Program	All EPUs	EMCB	SRXB	5.3.1 Draft Rev. 2 April 1996	GDC-14 GDC-31 10 CFR Part 50, App. H 10 CFR 50.60	RG 1.190	2.1.1	2.1.1	3.2.1, 10.7 HCGS NOTE
Pressure-Temperature Limits and Upper-Shelf Energy	All EPUs	EMCB	SRXB	5.3.2 Draft Rev. 2 April 1996	GDC-14 GDC-31 10 CFR Part 50, App. G 10 CFR 50.60	RG 1.161 RG 1.190 RG 1.99	2.1.2	2.1.2	3.2.1; Table 3-1 HCGS NOTE
Pressurized Thermal Shock	PWR EPUs	EMCB	SRXB	5.3.2 Draft Rev. 2 April 1996	GDC-14 GDC-31 10 CFR 50.61	RG 1.190 RG 1.154		2.1.3	NA for BWRs
Reactor Internal and Core Support Materials	All EPUs	EMCB	SRXB	4.5.2 Draft Rev. 3 April 1996	GDC-1 10 CFR 50.55a	Note 1*	2.1.3	2.1.4	3.3.2, 3.3.3, 3.4.2 & 10.7

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Reactor Coolant Pressure Boundary Materials	All EPUs	EMCB	EMEB SRXB	5.2.3 Draft Rev. 3 April 1996	GDC-1 10 CFR 50.55a GDC-4 GDC-14 GDC-31 10 CFR Part 50, App. G	RG 1.190 GL 97-01 IN 00-17s1 BL 01-01 BL 02-01 BL 02-02 Note 2* Note 3*	2.1.4	2.1.5	2.5.3, 3.1, 3.2, 3.4.1 (FIV), 3.5.1 and 10.7(FAC) HCGS NOTE
				4.5.1 Draft Rev. 3 April 1996	GDC-1 10 CFR 50.55a GDC-14				
				5.2.4 Draft Rev. 2 April 1996	10 CFR 50.55a				
				5.3.1 Draft Rev. 2 April 1996	GDC-1 10 CFR 50.55a GDC-4 GDC-14 GDC-31 10 CFR Part 50, App. G				
				5.3.3 Draft Rev. 2 April 1996					
				6.1.1 Draft Rev. 2 April 1996					
Leak-Before-Break	PWR EPUs	EMCB		3.6.3 Draft Aug. 1987	GDC-4	NUREG 1061 Vol. 3 Nov. 1984		2.1.6	NA for BWRs
Protective Coating Systems (Paints) - Organic Materials	All EPUs	EMCB		6.1.2 Draft Rev. 3 April 1996	10 CFR Part 50, App. B RG 1.54		2.1.5	2.1.7	4.2.6

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Effect of EPU on Flow-Accelerated Corrosion	All EPUs	EMCB				Note 4*	2.1.6	2.1.8	10.7
Steam Generator Tube Inservice Inspection	PWR EPUs	EMCB		5.4.2.2 Draft Rev. 2 April 1996	10 CFR 50.55a	Plant TSs RG 1.121 GL 95-03 BL 88-02 GL 95-05 Note 5*		2.1.9	NA for BWRs
Steam Generator Blowdown System	PWR EPUs	EMCB		10.4.8 Draft Rev. 3 April 1996	GDC-14			2.1.10	NA for BWRs
Chemical and Volume Control System (Including Boron Recovery System)	PWR EPUs	EMCB	SPLB SRXB	9.3.4 Draft Rev. 3 April 1996	GDC-14 GDC-29			2.1.11	NA for BWRs
Reactor Water Cleanup System	BWR EPUs	EMCB		5.4.8 Draft Rev. 3 April 1996	GDC-14 GDC-60 GDC-61		2.1.7		3.11, 5.2.4, 8.1 and 10.1

Notes:

1. In addition to the SRP, guidance on the neutron irradiation-related threshold for inspection for irradiation-assisted stress-corrosion cracking for BWRs is in BWRVIP-26 and for PWRs in BAW-2248 for E>1 MeV and in WCAP-14577 for E>0.1 MeV. For intergranular stress-corrosion cracking and stress-corrosion cracking in BWRs, review criteria and review guidance is contained in BWRVIP reports and associated staff safety evaluations. For thermal and neutron embrittlement of cast austenitic stainless steel, stress-corrosion cracking, and void swelling, licensees will need to provide plant-specific degradation management programs or participate in industry programs to investigate degradation effects and determine appropriate management programs.

2. For thermal aging of cast austenitic stainless steel, review guidance and criteria is contained in the May 19, 2000, letter from C. Grimes to D. Walters, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components."

3. For intergranular stress corrosion cracking in BWR piping, review criteria and review guidance is contained in BWRVIP reports, NUREG-0313, Revision 2, GL 88-01, Supplement 1 to GL-88-01, and associated safety evaluations.

4. Criteria and review guidance needed to review EPU applications in the area of flow-accelerated corrosion is contained in Electric Power Research Institute (EPRI) Report NSAC-202L-R2, "Recommendations for Effective an Flow-Accelerated Corrosion Program," dated April 1999. This EPRI document is copyrighted. EPRI has provided copies of this document to EMCB for use by NRC staff. Copying of this document, however, is not allowed.

5. Also see the plant-specific license amendments approving alternate repair criteria and redefining inspection boundaries.

HCGS NOTES - MATRIX 1

SE 2.1.1, Reactor Vessel Material Surveillance Program. NRC approved License Amendment 151, dated July 23, 2004, which revised the reactor vessel surveillance program to follow the BWRVIP Integrated Surveillance Program as the basis for meeting 10 CFR 50 Appendix H.

SE 2.1.2, Pressure-Temperature Limits and Upper-Shelf Energy. NRC approved License Amendment 157, dated November 1, 2004, which revises the reactor pressure vessel pressure-temperature limits and extends their validity to 32 effective full-power years. The supporting analyses were based on operation of the reactor at 3952 MW for the remaining 17 years of its operating license.

SE 2.1.4, Reactor Coolant Pressure Boundary Materials. A supplemental report describing the vibration monitoring test plan being implemented in support of the HCGS EPU project is submitted as part of the CPPU application.

Materials of construction for the reactor recirculation system piping are identified in PSEG letters dated July 29, 1988 and June 2, 1989 in response to Generic Letter 88-01.

Examination of welds identified as Category A IGSCC inspection locations is subsumed by the risk-informed inservice inspection (RI-ISI) program approved as an alternative to the requirements of ASME Code, Section XI (TAC No. MC2221). The number and locations of Non-Destructive Examination (NDE) inspections for Category A IGSCC locations will be evaluated for EPU in accordance with the requirements of the RI-ISI program.

Non-Category A IGSCC inspection locations are described in PSEG's letter dated August 20, 2004. These non-Category A locations will continue to be inspected in accordance with the requirements of GL 88-01 or the alternative criteria of EPRI report TR-113932, "BWR Vessel and Internals Project, Technical Basis for Revisions to Generic Letter (GL) 88-01 Inspection Schedules (BWRVIP-75)." EPU is not expected to affect susceptibility to the initiation and propagation of IGSCC because residual weld stresses are unaffected and system pressure, temperature and flow rate are not changed significantly.

MATRIX 2

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Mechanical and Civil Engineering

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Pipe Rupture Locations and Associated Dynamic Effects	All EPUs	EMEB		3.6.2 Draft Rev. 2 April 1996	GDC-4		2.2.1	2.2.1	3.5, 10.1 and 10.2 HCGS NOTE
Pressure-Retaining Components and Component Supports	All EPUs	EMEB		3.9.1 Draft Rev. 3 April 1996	GDC-1 GDC-2 GDC-14 GDC-15		2.2.2	2.2.2	2.5.3, 3.1, 3.2.2, 3.4, 3.5, 3.6, 3.7, 3.8 and 4.1.6 HCGS NOTE
				3.9.2 Draft Rev. 3 April 1996	GDC-1 GDC-2 GDC-4 GDC-14 GDC-15	IN 95-016 IN 02-026			
				3.9.3 Draft Rev. 2 April 1996	10 CFR 50.55a GDC-1 GDC-2 GDC-4 GDC-14 GDC-15	IN 96-049 GL 96-06			

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
			[redacted]	5.2.1.1 Draft Rev. 3 April 1996	10 CFR 50.55a GDC-1	RG 1.84 RG 1.147 DG 1.1089 DG 1.1090 DG 1091			
Reactor Pressure Vessel Internals and Core Supports	All EPUs	EMEB	[redacted]	3.9.1 Draft Rev. 3 April 1996	GDC-1 GDC-2	[redacted]	2.2.3	2.2.3	2.1, 3.3, 3.4.2, HCGS NOTE
			[redacted]	3.9.2 Draft Rev. 3 April 1996	GDC-1 GDC-2 GDC-4	IN 95-016 IN 02-026			
			[redacted]	3.9.3 Draft Rev. 2 April 1996	10 CFR 50.55a GDC-1 GDC-2 GDC-4	IN 96-049 GL 96-06			
			[redacted]	3.9.5 Draft Rev. 3 April 1996	10 CFR 50.55a GDC-1 GDC-2 GDC-4 GDC-10	IN 02-026 Note 1*			
Safety-Related Valves and Pumps	All EPUs	EMEB	[redacted]	3.9.3 Draft Rev. 2 April 1996	GDC-1 10 CFR 50.55a(f)	IN 96-049 GL 96-06	2.2.4	2.2.4	3.1, 3.8, 3.9, 3.10, 3.11, 4.1.3, 4.1.4, 4.1.6, 4.2, 4.3, 4.4,

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
				3.9.6 Draft Rev. 3 April 1996	GDC-1 GDC-37 GDC-40 GDC-43 GDC-46 GDC-54 10 CFR 50.55a(f)	GL 89-10 GL 95-07 GL 96-05 IN 97-090 IN 96-048s1 IN 96-048 IN 96-003 RIS 00-003 RIS 01-015 RG 1.147 RG 1.175 DG 1089 DG 1091			4.1.6, 4.2, 4.3, 4.4, and 4.5 HCGS NOTE
Seismic and Dynamic Qualification of Mechanical and Electrical Equipment	All EPUs	EMEB	EEIB	3.10 Draft Rev. 3 April 1996	GDC-1 GDC-2 GDC-4 GDC-14 GDC-30 10 CFR Part 100, App. A 10 CFR Part 50, App. B USI A-46		2.2.5	2.2.5	3.3.2, 4.1.2, 10.1 & 10.3 HCGS NOTE

Notes:

1. As indicated in IN 2002-26 and Supplement 1 to IN 2002-26, the steam dryers and other plant components recently failed at Quad Cities Units 1 and 2 during operation under extended power uprate (EPU) conditions. The failures occurred as a result of high-cycle fatigue caused by increased flow-induced vibrations at EPU conditions. The staff's review of the reactor internals as part of EPU requests will cover detailed analyses of flow-induced vibration and acoustically-

induced vibration (where applicable) on reactor internal components such as steam dryers and separators, and the jet pump sensing lines that are affected by the increased steam and feedwater flow for EPU conditions. In addition, the staff is evaluating the need to address potential adverse effects on other plant components from the increased steam and feedwater flow under EPU conditions.

HCGS NOTES - MATRIX 2

SE 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects. - The review of the postulated pipe break criteria determined that for the FW piping at three locations, the cumulative fatigue usage exceeds the postulated pipe break criteria limit. The existing calculations for these locations will be reviewed to reconcile the cumulative fatigue usage prior to implementation of the CPPU.

SE 2.2.2, Pressure Retaining Components and Component Supports. NRC approved License Amendment 157, dated November 1, 2004, which revises the reactor pressure vessel pressure-temperature limits and extends their validity to 32 effective full-power years. The supporting analyses were based on operation of the reactor at 3952 MW for the remaining 17 years of its operating license. The FIV analysis concluded that for MS and FW piping, a piping vibration startup test program, consistent with the ASME code and regulatory requirements, will be performed. Modifications to pipe supports on the Main Steam System (Outside Containment) will be completed prior to implementing CPPU.

SE 2.2.3, Reactor Pressure Vessel Internals and Core Supports. Steam Dryer/separator performance testing will be conducted in the CPPU power ascension (PUSAR section 10.4). A detailed evaluation of the steam dryer is described in Attachment 7 to the License Change Request. Additional discussion of reactor internal pressure differences is provided in Section 4.0 of the Cycle 13 and EPU Fuel Transition Reports.

SE 2.2.4, Safety-Related Valves and Pumps. The HCGS periodic MOV testing program was reviewed and found acceptable by NRC in its SE dated Dec. 7, 1999 "Safety Evaluation of Licensee Response to Generic Letter 96-05...". PSEG implemented a risk informed ISI Program at HCGS iaw RG 1.178 as authorized by NRC Letter, "HCGS Implementation of a Risk-Informed Inservice Inspection Program" and attached SER, dated December 8, 2004.

SE 2.2.5, Seismic and Dynamic Qualification of Mechanical and Electrical Equipment. RS-001 Section 2.2.5 focuses on the qualification of equipment to withstand seismic events and the dynamic effects associated with pipe whip and jet impingement forces. Consistent with the RS-001, the HCGS evaluation concludes that the primary input motions due to the safe shutdown earthquake (SSE) are not affected by an EPU. The dynamic effects associated with pipe whip and jet impingement are evaluated.

MATRIX 3

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Electrical Engineering

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Environmental Qualification of Electrical Equipment	All EPUs	EEIB		3.11 Draft Rev. 3 April 1996	10 CFR 50.49		2.3.1	2.3.1	10.3.1 HCGS NOTE
Offsite Power System	All EPUs	EEIB		8.1 Draft Rev. 3 April 1996	GDC-17	BTP PSB-1 Draft Rev. 3 April 1996 BTP ICSB-11 Draft Rev. 3 April 1996	2.3.2	2.3.2	6.1.1 HCGS NOTE
				8.2 Draft Rev. 4 April 1996	GDC-17				
				8.2, App. A Draft Rev. 4 April 1996	GDC-17				
AC Onsite Power System	All EPUs	EEIB		8.1 Draft Rev. 3 April 1996	GDC-17		2.3.3	2.3.3	6.1.2
				8.3.1 Draft Rev. 3 April 1996	GDC-17				

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
DC Onsite Power System	All EPUs	EEIB		8.1 Draft Rev. 3 April 1996	GDC-17 10 CFR 50.63		2.3.4	2.3.4	6.2
				8.3.2 Draft Rev. 3 April 1996	GDC-17 10 CFR 50.63				
Station Blackout	All EPUs	EEIB	SPLB SRXB	8.1 Draft Rev. 3 April 1996	10 CFR 50.63	Note 1*	2.3.5	2.3.5	9.3.2 HCGS NOTE
				8.2, App. B Draft Rev. 4 April 1996	10 CFR 50.63				

1. The review of station blackout includes the effects of the EPU on systems relied upon for core cooling in the station blackout coping analysis (e.g., condensate storage tank inventory, controls and power supplies for relief valves, residual heat removing system) to ensure that the effects are accounted for in the analysis.

HCGS NOTES - MATRIX 3

SE 2.3.2, Offsite Power System. A supplemental report documenting the grid stability analysis which was performed is provided in Attachment 9 to the License Change Request.

SE 2.3.5, Station Blackout. HCGS Station Blackout Analysis was performed using the guidelines in Regulatory Guide 1.155 and NUMARC 87-00

MATRIX 4

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Instrumentation and Controls

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Reactor Trip System	All EPUs	EEIB		7.2 Rev. 4 June 1997	10 CFR 50.55(a)(1) 10 CFR 50.55a(h) GDC-1 GDC-4 GDC-13 GDC-19 GDC-20 GDC-21 GDC-22 GDC-23 GDC-24		2.4.1	2.4.1	5.3, 9.1.1 & 10.4 HCGS NOTE
Engineered Safety Features Systems	All EPUs	EEIB		7.3 Rev. 4 June 1997			2.4.1	2.4.1	5.3
Safety Shutdown Systems	All EPUs	EEIB		7.4 Rev. 4 June 1997	10 CFR 50.55(a)(1) 10 CFR 50.55a(h) GDC-1 GDC-4 GDC-13 GDC-19 GDC-24		2.4.1	2.4.1	5.3

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Control Systems	All EPUs	EEIB		7.7 Rev. 4 June 1997	10 CFR 50.55(a)(1) 10 CFR 50.55a(h) GDC-1 GDC-13 GDC-19 GDC-24		2.4.1	2.4.1	5.1 (NSSS) 5.2 (BOP) & 5.3
Diverse I&C Systems	All EPUs	EEIB		7.8 Rev. 4 June 1997			2.4.1	2.4.1	5.1, 5.2 & 5.3
General guidance for use of other SRP Sections related to I&C	All EPUs	EEIB		7.0 Rev. 4 June 1997					

HCGS NOTES - MATRIX 4

SE 2.4.1 Reactor Trip System. PSEG Letter LR-N04-0062, "Request for License Amendment ARTS/MELLLA Implementation", June 7, 2004 provides the basis for reactor trip setpoints for APRM flow biased power, RWM thermal power, APRM Neutron Flux upscale and setdown trip. This submittal assumes prior approval of the ARTS/MELLLA License Change Request.

MATRIX 5

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Plant Systems

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Flood Protection	EPUs that result in significant increases in fluid volumes of tanks and vessels	SPLB		3.4.1 Rev. 2 July 1981	GDC-2		2.5.1.1.1	2.5.1.1.1	10.1.2, 10.2, 10.5 HCGS NOTE
Equipment and Floor Drainage System	EPUs that result in increases in fluid volumes or in installation of larger capacity pumps or piping systems	SPLB		9.3.3 Rev. 2 July 1981	GDC-2 GDC-4		2.5.1.1.2	2.5.1.1.2	8.1
Circulating Water System	EPUs that result in increases in fluid volumes associated with the circulating water system or in installation of larger capacity pumps or piping systems	SPLB		10.4.5 Rev. 2 July 1981	GDC-4		2.5.1.1.3	2.5.1.1.3	6.4.1 & 6.4.2
Internally Generated Missiles (Outside Containment)	EPUs that result in substantially higher system pressures or changes in existing system configuration	SPLB	EMCB EMEB	3.5.1.1 Rev. 2 July 1981	GDC-4		2.5.1.2.1	2.5.1.2.1	7.1 HCGS NOTE

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Internally Generated Missiles (Inside Containment)	EPUs that result in substantially higher system pressures or changes in existing system configuration	SPLB	EMCB EMEB	3.5.1.2 Rev. 2 July 1981	GDC-4		2.5.1.2.1	2.5.1.2.1	10.1.2 HCGS NOTE
Turbine Generator	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.2 Rev. 2 July 1981	GDC-4		2.5.1.2.2	2.5.1.2.2	7.1 HCGS NOTE
Protection Against Postulated Piping Failures in Fluid Systems Outside Containment	EPUs that affect environmental conditions, habitability of the control room, or access to areas important to safe control of postaccident operations	SPLB	EMCB EMEB	3.6.1 Rev. 1 July 1981	GDC-4		2.5.1.3	2.5.1.3	8.5, 9.2, 10.1 & 10.2
Fire Protection Program	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		9.5.1 Rev. 3 July 1981	10 CFR 50.48 10 CFR Part 50, App. R GDC-3 GDC-5	Note 1*	2.5.1.4	2.5.1.4	6.7
Pressurizer Relief Tank	PWR EPUs that affect pressurizer discharge to the PRT	SPLB	EMEB	5.4.11 Rev. 2 July 1981	GDC-2 GDC-4			2.5.2	NA for BWRs

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Fission Product Control Systems and Structures	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB	EMCB	6.5.3 Rev. 2 July 1981	GDC-41		2.5.2.1	2.5.3.1	4.1 (Containment) & 4.5 (FRVS) HCGS NOTE
Main Condenser Evacuation System	EPUs for which the main condenser evacuation system is modified	SPLB		10.4.2 Rev. 2 July 1981	GDC-60 GDC-64		2.5.2.2	2.5.3.2	7.2
Turbine Gland Sealing System	EPUs for which the turbine gland sealing system is modified	SPLB		10.4.3 Rev. 2 July 1981	GDC-60 GDC-64		2.5.2.3	2.5.3.3	7.1 HCGS NOTE
Main Steam Isolation Valve Leakage Control System	BWR EPU that affect the amount of valve leakage that is assumed and resultant dose consequences.	SPLB		6.7 Rev. 2 July 1981	GDC-54		2.5.2.4		4.6 HCGS NOTE
Spent Fuel Pool Cooling and Cleanup System	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB	EMCB	9.1.3 Rev. 1 July 1981	GDC-5 GDC-44 GDC-61	Note 2*	2.5.3.1	2.5.4.1	6.3.1 HCGS NOTE
Station Service Water System	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		9.2.1 Rev. 4 June 1985	GDC-4 GDC-5 GDC-44	GL 89-13 and Suppl. 1 GL 96-06 and Suppl. 1	2.5.3.2	2.5.4.2	6.4.1.1.1

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Reactor Auxiliary Cooling Water Systems	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		9.2.2 Rev. 3 June 1986	GDC-4 GDC-5 GDC-44	GL 89-13 and Suppl. 1 GL 96-06 and Suppl. 1	2.5.3.3	2.5.4.3	6.4.1.1.2
Ultimate Heat Sink	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		9.2.5 Rev. 2 July 1981	GDC-5 GDC-44		2.5.3.4	2.5.4.4	6.4.1, 6.4.2 & 6.4.5
Auxiliary Feedwater System	PWR EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.4.9 Rev. 2 July 1981	GDC-4 GDC-5 GDC-19 GDC-34 GDC-44			2.5.4.5	NA for BWRs
Main Steam Supply System	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.3 Rev. 3 April 1984	GDC-4 GDC-5 GDC-34		2.5.4.1	2.5.5.1	3.5.1, 3.7, 3.8, 5.3 & 7.3
Main Condenser	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.4.1 Rev. 2 July 1981	GDC-60		2.5.4.2	2.5.5.2	6.4.2 & 7.2
Turbine Bypass System	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.4.4 Rev. 2 July 1981	GDC-4 GDC-34		2.5.4.3	2.5.5.3	7.3

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Condensate and Feedwater System	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.4.7 Rev. 3 April 1984	GDC-4 GDC-5 GDC-44		2.5.4.4	2.5.5.4	7.4
Gaseous Waste Management Systems	EPUs that impact the level of fission products in the reactor coolant system, or the amount of gaseous waste	SPLB	IEPB	11.3 Draft Rev. 3 April 1996	10 CFR 20.1302 GDC-3 GDC-60 GDC-61 10 CFR Part 50, App. I		2.5.5.1	2.5.6.1	8.2 & 8.6
Liquid Waste Management Systems	EPUs that impact the level of fission products in the reactor coolant system, or the amount of liquid waste	SPLB	IEPB	11.2 Draft Rev. 3 April 1996	10 CFR 20.1302 GDC-60 GDC-61 10 CFR Part 50,App. I		2.5.5.2	2.5.6.2	8.1 & 8.6
Solid Waste Management Systems	EPUs that impact the level of fission products in the reactor coolant system, or the amount of solid waste	SPLB	IEPB	11.4 Draft Rev. 3 April 1996	10 CFR 20.1302 GDC-60 GDC-63 GDC-64 10 CFR Part 71		2.5.5.3	2.5.6.3	8.1
Emergency Diesel Engine Fuel Oil Storage and Transfer System	EPUs that result in higher EDG electrical demands	SPLB		9.5.4 Rev. 2 July 1981	GDC-4 GDC-5 GDC-17		2.5.6.1	2.5.7.1	6.1.1, Table 6-5 HCGS NOTE

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Light Load Handling System (Related to Refueling)	EPUs except where the application demonstrates that previous analysis is bounding	SPLB	SPSB	9.1.4 Rev. 2 July 1981	GDC-61 GDC-62	[redacted]	2.5.6.2	2.5.7.2	Table 6-5 HCGS NOTE

Notes:
1. Supplemental guidance for review of fire protection is provided in Attachment 1 to this matrix.
2. Supplemental guidance for review of spent fuel pool cooling is provided in Attachment 2 to this matrix.

HCGS NOTES - MATRIX 5

SE 2.5.1.1.1, Flood Protection. RS-001 Section 2.5.1.1 focuses on increases of fluid volumes in tanks and vessels assumed in the flooding analysis. The limiting flooding events at HCGS, however are not controlled by fluid volumes in tanks and vessels, but result from open cycle systems such as Service Water, Fire Water, and Circulating Water system. The HCGS flooding analysis determined that the CPPU may result in Flood Level increases of up to 36% in certain areas but that the equipment in the affected areas has been previously analyzed for wetting, submergence or is above the specific flood level determined for the affected area.

SE 2.5.1.2.1, Internally Generated Missiles. RS-001 Matrix 5 states that this review criterion is applicable to EPUs that result in substantially higher system pressures or changes in existing system configuration. The HCGS CPPU does not result in any condition (system pressure increase or equipment overspeed) that could result in an increase in the generation of internally generated missiles. In addition, the HCGS CPPU does not entail any changes in equipment configurations that could change the effect of internally generated missiles on safety-related or non-safety related equipment. Although the HCGS CPPU will result an increase in the extraction steam pressures, these lines are within the turbine building which does not contain SSCs important to safety.

SE 2.5.1.2.2, Turbine Generator. HCGS HP and LP turbine rotors have been converted to the monoblock design and both the "normal overspeed" and "emergency overspeed" trip values were confirmed. The Low Pressure (LP) Turbine rotors at Hope Creek have now been converted to the monoblock design from the original built-up design that was installed with the original construction of the plant. This LP rotor conversion from built-up to the monoblock design effectively increased total rotor inertia values by more than 21% over the original rotors. This large increase in inertia slows the accelerations rate of the machine should a load rejection event occur. For the same conversion, the flow increases enabling the power output of the machine to increase almost 20% over the original power levels. From an overspeed standpoint, these two changes effectively cancel each other out, such that the estimated peak speed following a full load rejection remains virtually unchanged from its original estimated value of 109.26% of rated speed. The latest estimate following the LP conversion is, 109.20% of rated speed. GE refers to this estimated peak speed as "normal overspeed" or, NOS. For NOS, it is assumed that all protective steam valves and control systems have responded as intended to minimize the resulting peak speed.

Consequently, there is no need to adjust the design setting of the mechanical trip, which remains at 109.9 - 110.4% of rated speed, as there is still sufficient margin between the NOS value and the minimum mechanical trip setting. This margin should normally be at least 0.5%, and presently, it is 0.7%.

GE also calculates a second overspeed value, referred to as, "emergency overspeed", or EOS. This is the estimated peak speed following a full load rejection event when it is assumed the first line-of-defense valves (i.e., control and intercept valves) and speed control systems completely fail. The unit would rapidly accelerate to the mechanical trip speed range, which would activate the trip function and close the main and intermediate stop valves. The resulting peak speed is called the emergency overspeed value. The limit for EOS is 120% of rated. Considering this LP monoblock steam path conversion, the present EOS value is, 119.35% of rated speed, which is actually less than the original value of 119.85%, and thus, is fully acceptable.

Consequently, the uprated overspeed characteristics are all within GE's experience and within all operating limits. All protective systems will function as before with no loss of overspeed protection.

As stated above, the HP and LP turbine rotors at Hope Creek are of the GE monoblock design, i.e. integral, non-shrunk on wheels. GE has shown that a separate turbine missile analysis is not required for CPPU if the turbine rotors are of the integral, non-shrunk on wheel type. Since the turbine peak overspeed at EPU conditions is less than that of the original construction of this unit, and because of the use of monoblock rotors, equipment important to safety will continue to be protected from the effects of turbine missiles. (ref. Constant Pressure Power Uprate Licensing Topical Report (NEDC 33004P-A, Revision 4)

SE 2.5.2.1, Fission Product Control. NRC approved HCGS License Amendment 134, which authorized implementation of an alternative source term (AST). A specific analysis of FRVS (Standby Gas Treatment) has been performed to demonstrate that the performance post CPPU continues to be bounded by the CLTR.

SE 2.5.2.3, Turbine Gland Seal. This system will be modified as described in the PUSAR section 7.1 as part of the implementation of the CPPU. Additional modifications to the HP turbine packing heads will be made as part of the new rotor design.

SE 2.5.2.4, Main Steam Isolation Valve Leakage Control System. NRC approved License Amendment 134, which authorized removing the MSIV Sealing System.

SE 2.5.3.1, Spent Fuel Pool Cooling and Cleanup System. For CPPU the Spent Fuel Pool Cooling was analyzed with both loops in service and a failure of the RHR Fuel Pool Cooling assist as the single failure. Additionally, GE used

ANS 5.1-1979 for the calculation of the Fuel Pool heat loads.

<u>SE 2.5.6.1, Emergency Diesel Engine Fuel Oil Storage and Transfer System</u>. This system is evaluated generically under CLTR (see Table 6-5)

<u>SE 2.5.6.2, Light Load Handling System (Related to Refueling).</u> This system is evaluated generically under the CLTR. The justification for classifying it as No Significant Impact is provided in Table 6-5.

MATRIX 6

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Containment Review Considerations

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
PWR Dry Containments, Including Subatmospheric Containments	EPUs for PWR plants with dry containments (including subatmospheric containments) except where the application demonstrates that previous analysis is bounding	SPSB		6.2.1 Rev. 2 July 1981 6.2.1.1.A Rev. 2 July 1981	GDC-13 GDC-16 GDC-38 GDC-50 GDC-64			2.6.1	NA for BWRs
Ice Condenser Containments	EPUs for PWR plants with ice condenser containments except where the application demonstrates that previous analysis is bounding	SPSB		6.2.1 Rev. 2 July 1981 6.2.1.1.B Rev. 2 July 1981	GDC-13 GDC-16 GDC-38 GDC-50 GDC-64			2.6.1	NA for BWRs
Pressure-Suppression Type BWR Containments	EPUs for BWR plants with pressure-suppression containments except where the application demonstrates that previous analysis is bounding	SPSB		6.2.1 Rev. 2 July 1981 6.2.1.1.C Rev. 6 Aug. 1984	GDC-4 GDC-13 GDC-16 GDC-50 GDC-64		2.6.1		4.1 thru 4.1.3, 9.2, 9.3.2, 10.3.1 HCGS NOTE

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Subcompartment Analysis	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB		6.2.1 Rev. 2 July 1981 6.2.1.2 Rev. 2 July 1981	GDC-4 GDC-50		2.6.2	2.6.2	4.1.2.3 HCGS NOTE
Mass and Energy Release Analysis for Postulated Loss-of-Coolant	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB		6.2.1 Rev. 2 July 1981 6.2.1.3 Rev. 1 July 1981	GDC-50 10 CFR Part 50, App. K		2.6.3.1	2.6.3.1	4.1 thru 4.1.2.2, 10.1
Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures	PWR EPUs except where the application demonstrates that previous analysis is bounding	SPSB		6.2.1 Rev. 2 July 1981 6.2.1.4 Rev. 1 July 1981	GDC-50			2.6.3.2	NA for BWRs
Combustible Gas Control In Containment	EPUs that impact hydrogen release assumptions	SPSB		6.2.5 Rev. 2 July 1981	10 CFR 50.44 10 CFR 50.46 GDC-5 GDC-41 GDC-42 GDC-43		2.6.4	2.6.4	4.7

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Containment Heat Removal	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB		6.2.2 Rev. 4 Oct. 1985	GDC-38	DG-1107	2.6.5	2.6.5	3.10
Secondary Containment Functional Design	EPUs that affect the pressure and temperature response, or draw-down time of the secondary containment	SPSB		6.2.3 Rev. 2 July 1981	GDC-4 GDC-16		2.6.6		4.5
Minimum Containment Pressure Analysis for Emergency Core Cooling System Performance Capability Studies	PWR EPUs except where the application demonstrates that previous analysis is bounding	SPSB	SRXB	6.2.1 Rev. 2 July 1981 6.2.1.5 Rev. 2 July 1981	10 CFR 50.46 10 CFR Part 50, App. K			2.6.6	NA for BWRs

HCGS NOTES - MATRIX 6

SE 2.6.1, Primary Containment Functional Design. NRC approved HCGS License Amendment 134 authorizing implementation of Alternative Source Term (AST) methodology. The evaluation of Primary Containment considers AST parameters.

SE 2.6.2, Subcompartment Analysis. The calculation of mass and energy releases for the MELLLA condition, including revised annulus pressurization loading methodology, are bounding for CPPU and are described in PSEG letter LR-N04-0062, "Request for License Amendment: ARTS/MELLLA Implementation," June 7, 2004.

MATRIX 7

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Habitability, Filtration, and Ventilation

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Control Room Habitability System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB		6.4 Draft Rev. 3 April 1996	GDC-4 GDC-19	Note 1* Note 2*	2.7.1	2.7.1	4.4 HCGS NOTE
ESF Atmosphere Cleanup System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB		6.5.1 Rev. 2 July 1981	GDC-19 GDC-41 GDC-61 GDC-64		2.7.2	2.7.2	4.5 HCGS NOTE
Control Room Area Ventilation System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB		9.4.1 Rev. 2 July 1981	GDC-4 GDC-19 GDC-60		2.7.3	2.7.3	4.4 HCGS NOTE
Spent Fuel Pool Area Ventilation System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB		9.4.2 Rev. 2 July 1981	GDC-60 GDC-61		2.7.4	2.7.4	4.5, 6.6 & 9.2 HCGS NOTE
Auxiliary and Radwaste Area Ventilation System	All EPUs except where the application demonstrates that	SPSB		9.4.3 Rev. 2 July 1981	GDC-60		2.7.5	2.7.5	6.6

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
	previous analysis is bounding		[redacted]			[redacted]			
Turbine Area Ventilation System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB	[redacted]	9.4.4 Rev. 2 July 1981	GDC-60	[redacted]	2.7.5	2.7.5	6.6
ESF Ventilation System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB	[redacted]	9.4.5 Rev. 2 July 1981	GDC-4 GDC-17 GDC-60	[redacted]	2.7.6	2.7.6	6.4.1.1.2 & 6.6 HCGS NOTE

Notes:

1. Under SRP Section 6.4, Section II, "Acceptance Criteria," the discussion for Item C related to GDC-19 should be supplemented with "and providing a suitably controlled environment for the control room operators and the equipment located therein."

2. Under SRP Section 6.4, Section II, Item 2, "Ventilation System Criteria," the discussion related to review of the control room area ventilation system under SRP Section 9.4.1 should be retained.

HCGS NOTES - MATRIX 7

SE 2.7.1, Control Room Habitability System. The HCGS Control Room Habitability System was reanalyzed for various DBAs using the CPPU core inventory and the previously approved Alternative Source Term methodology (ref. License Amendment No. 134). The CPPU impact evaluation and acceptance criteria are derived from 10 CFR 50.67 and RG 1.1.83 as reflected in section 4.4 of the PUSAR.

SE 2.7.2, ESF Atmosphere Cleanup. The Filtration, Recirculation and Ventilation System (FRVS) is evaluated using CPPU conditions and AST methodology approved in License Amendment 134. The CPPU impact evaluation and acceptance criteria are derived from 10 CFR 50.67, Reg Guide 1.1.83 and Reg Guide 1.52 for charcoal filters.

SE 2.7.3, Control Room Air Ventilation System The HCGS Control Room Emergency Filtration System (CREF) is evaluated using CPPU conditions and AST methodology approved in License Amendment 134 and meets the requirements of 10 CFR 50.67 and Reg Guides 1.183 and 1.52. The CPPU impact evaluation and acceptance criteria are derived from 10 CFR 50.67, RG 1.183 and RG 1.52 as reflected in section 4.4 of the PUSAR.

SE 2.7.4, Spent Fuel Pool Area Ventilation System. HCGS does not have a separate Spent Fuel Pool Area Ventilation System.

SE 2.7.6, ESF Ventilation System. The CPPU evaluations show slight increase in temperatures due to power uprate but that the equipment is adequately cooled and remains environmentally qualified.

MATRIX 8

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Reactor Systems

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Fuel System Design	All EPUs	SRXB		4.2 Draft Rev. 3 April 1996	10 CFR 50.46 GDC-10 GDC-27 GDC-35	Note 1* Note 2*	2.8.1	2.8.1	2.1, 2.2, 2.3, 4.3 & 9.1 HCGS NOTE
Nuclear Design	All EPUs	SRXB		4.3 Draft Rev. 3 April 1996	GDC-10 GDC-11 GDC-12 GDC-13 GDC-20 GDC-25 GDC-26 GDC-27 GDC-28	RG 1.190 GSI 170 IN 97-085	2.8.2	2.8.2	2.1,2.2, 2.3, 2.4, 2.5, 4.3, 5.1, 5.3, 9.1, 9.2 & 9.3 HCGS NOTE
Thermal and Hydraulic Design	All EPUs	SRXB		4.4 Draft Rev. 2 April 1996	GDC-10 GDC-12	Note 3*	2.8.3	2.8.3	2.1, 2.2, 2.3, 2.4, 5.3, 9.1 & 9.3 HCGS NOTE
Functional Design of Control Rod Drive System	All EPUs	SRXB	SPLB	4.6 Draft Rev. 2 April 1996	GDC-4 GDC-23 GDC-25 GDC-26 GDC-27 GDC-28 GDC-29 10 CFR		2.8.4.1	2.8.4.1	2.5

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
					50.62(c)(3)				
Overpressure Protection during Power Operation	All EPUs	SRXB		5.2.2 Draft Rev. 3 April 1996	GDC-15 GDC-31	Note 4*	2.8.4.2	2.8.4.2	3.1 HGCS NOTE
Overpressure Protection during Low Temperature Operation	PWR EPUs	SRXB		5.2.2 Draft Rev. 3 April 1996	GDC-15 GDC-31			2.8.4.3	NA for BWRs
Reactor Core Isolation Cooling System	BWR EPUs	SRXB		5.4.6 Draft Rev. 4 April 1996	GDC-4 GDC-5 GDC-29 GDC-33 GDC-34 GDC-54 10 CFR 50.63		2.8.4.3		3.9 & 9.3.2
Residual Heat Removal System	All EPUs	SRXB		5.4.7 Draft Rev. 4 April 1996	GDC-4 GDC-5 GDC-19 GDC-34	Note 5*	2.8.4.4	2.8.4.4	3.10, 4.2.4, 4.2.6& 6.3
Emergency Core Cooling System	All EPUs	SRXB		6.3 Draft Rev. 3 April 1996	GDC-4 GDC-27 GDC-35 10 CFR 50.46 10 CFR Part 50, App. K	Note 6*	2.8.5.6.2	2.8.5.6.3	4.2, 4.3 & 10.6 HCGS NOTE
Standby Liquid Control System	BWR EPUs	SRXB	EMCB SPLB	9.3.5 Draft Rev. 3 April 1996	GDC-26 GDC-27 10 CFR 50.62(c)(4)	Note 10*	2.8.4.5		6.5 & 9.3.1 HCGS NOTE

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve	All EPUs	SRXB		15.1.1-4 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-20 GDC-26	Note 7*	2.8.5.1	2.8.5.1. 1	9.1 & Table 9-2 HCGS NOTE
Steam System Piping Failures Inside and Outside of Containment	PWR EPUs	SRXB		15.1.5 Draft Rev. 3 April 1996	GDC-27 GDC-28 GDC-31 GDC-35	Note 7*		2.8.5.1. 2	NA For BWRs
Loss of External Load; Turbine Trip, Loss of Condenser Vacuum; Closure of Main Steam Isolation Valve (BWR); and Steam Pressure Regulator Failure (Closed)	All EPUs	SRXB		15.2.1-5 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*	2.8.5.2.1	2.8.5.2. 1	3.1, 3.8 & 9.1 HCGS NOTE
Loss of Nonemergency AC Power to the Station Auxiliaries	All EPUs	SRXB		15.2.6 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*	2.8.5.2.2	2.8.5.2. 2	6.1 & 9.1 HCGS NOTE
Loss of Normal Feedwater Flow	All EPUs	SRXB	EEIB	15.2.7 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*	2.8.5.2.3	2.8.5.2. 3	3.9 & 9.1 HCGS NOTE

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Feedwater System Pipe Breaks Inside and Outside Containment	PWR EPUs	SRXB	EEIB	15.2.8 Draft Rev. 2 April 1996	GDC-27 GDC-28 GDC-31 GDC-35	Note 7*		2.8.5.2.4	NA for BWRs
Loss of Forced Reactor Coolant Flow Including Trip of Pump Motor and Flow Controller Malfunctions	All EPUs	SRXB		15.3.1-2 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*	2.8.5.3.1	2.8.5.3.1	9.1
Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break	All EPUs	SRXB		15.3.3-4 Draft Rev. 3 April 1996	GDC-27 GDC-28 GDC-31	Note 7*	2.8.5.3.2	2.8.5.3.2	9.1 HCGS NOTE
Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition	All EPUs	SRXB		15.4.1 Draft Rev. 3 April 1996	GDC-10 GDC-20 GDC-25	Note 7*	2.8.5.4.1	2.8.5.4.1	HCGS NOTE
Uncontrolled Control Rod Assembly Withdrawal at Power	All EPUs	SRXB		15.4.2 Draft Rev. 3 April 1996	GDC-10 GDC-20 GDC-25	Note 7*	2.8.5.4.2	2.8.5.4.2	5.3.5 & 9.1 HCGS NOTE
Control Rod Misoperation (System Malfunction or Operator Error)	PWR EPUs	SRXB		15.4.3 Draft Rev. 3 April 1996	GDC-10 GDC-20 GDC-25	Note 7*		2.8.5.4.3	NA for BWRs
Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and	All EPUs	SRXB		15.4.4-5 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-20 GDC-26	Note 7*	2.8.5.4.3	2.8.5.4.4	9.1 HCGS NOTE

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate					GDC-28				
Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant	PWR EPUs	SRXB		15.4.6 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*		2.8.5.4.5	NA for BWRs
Spectrum of Rod Ejection Accidents	PWR EPUs	SRXB		15.4.8 Draft Rev. 3 April 1996	GDC-28	Note 7*		2.8.5.4.6	NA for BWRs
Spectrum of Rod Drop Accidents	BWR EPUs	SRXB		15.4.9 Draft Rev. 3 April 1996	GDC-28	Note 7*	2.8.5.4.4		5.3, 9.2 HCGS NOTE
Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	All EPUs	SRXB		15.5.1-2 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7* Note 8*	2.8.5.5	2.8.5.5	9.1 HCGS NOTE
Inadvertent Opening of a PWR Pressurizer Pressure Relief Valve or a BWR Pressure Relief Valve	All EPUs	SRXB		15.6.1 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*	2.8.5.6.1	2.8.5.6.1	3.1, 9.1 HCGS NOTE

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Steam Generator Tube Rupture	PWR EPUs	SRXB		15.6.3 Draft Rev. 3 April 1996	Note 7*	Note 7*		2.8.5.6.2	NA for BWRs
Loss-of Coolant Accidents Resulting from Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary	All EPUs	SRXB		15.6.5 Draft Rev. 3 April 1996	GDC-35 10 CFR 50.46	Note 7* Note 9*	2.8.5.6.2	2.8.5.6.3	4.3 & 9.2 HCGS NOTE
Anticipated Transient Without Scram	All EPUs	SRXB				Note 7* Note 10*	2.8.5.7	2.8.5.7	6.5, 9.3.1 & 9.3.3 HCGS NOTE
New Fuel Storage	EPU applications that request approval for new fuel design.	SRXB		9.1.1 Draft Rev. 3 April 1996	GDC-62		2.8.6.1	2.8.6.1	6.3 HCGS NOTE
Spent Fuel Storage	EPU applications that request approval for new fuel design.	SRXB		9.1.2 Draft Rev. 4 April 1996	GDC-4 GDC-62		2.8.6.2	2.8.6.2	6.3 HCGS NOTE

Notes:

1. When mixed cores (i.e., fuels of different designs) are used, the review covers the licensee's evaluation of the effects of mixed cores on design-basis accident and transient analyses.

2. The current acceptance criteria for fuel damage for reactivity insertion accidents (RIAs) need revision per Research Information Letter No. 174, "Interim Assessment of Criteria for Analyzing Reactivity Accidents at High Burnup." The Office of Nuclear Regulatory Research is conducting confirmatory research on RIAs and the Office of

Nuclear Reactor Regulation is discussing the issue of fuel damage criteria with the nuclear power industry as part of the industry's proposal to increase future fuel burnup limits. In the interim, current methods for assessing fuel damage in RIAs are considered acceptable based on the NRC staff's understanding of actual fuel performance, as shown in three-dimensional kinetic calculations which indicate acceptably low fuel cladding enthalpy.

3. The review also covers core design changes and any effects on radial and bundle power distribution, including any changes in critical heat flux ratio and critical power ratio. The review will also confirm the adequacy of the flow-based average power range monitor flux trip and safety limit minimum critical power ratio at the uprated conditions.

4. The review also covers the determination of allowable power levels with inoperable main steam safety valves.

5. The review also covers the total time necessary to reach the shutdown cooling initiation temperature.

6. The review for BWRs will cover the justification for changes in calculated peak cladding temperature (PCT) for the design-basis case and the upper-bound case and any impact of the changes in PCTs on the use of the design methods for the power uprate.

7. The review:
   - confirms that the licensee used NRC-approved codes and methods for the plant-specific application and the licensee's use of the codes and methods complies with any limitations, restrictions, and conditions specified in the approving safety evaluation.
   - confirms that all changes of reactor protection system trip delays are correctly addressed and accounted for in the analyses.
   - (for PWRs) confirms that steam generator plugging and asymmetry limits are accounted for in the analyses.
   - (for PWRs) covers the licensee's evaluation of the effects of Westinghouse Nuclear Service Advisory Letters (NSALs), NSAL 02-3 and Revision 1, NSAL 02-4, and NSAL 02-5. These NSALs document problems with water level setpoint uncertainties in Westinghouse-designed steam generators. The review is conducted to ensure that the effects of the identified problems have been accounted for in steam generator water level setpoints used in LOCA, non-LOCA, and ATWS analyses.

8. For the inadvertent operation of emergency core cooling system and chemical and volume control system malfunctions that increase reactor coolant inventory events: (a) non-safety-grade pressure-operated relief valves should not be credited for event mitigation and (b) pressurizer level should not be allowed to reach a pressurizer water-solid condition.

9. The review also verifies that:
   - Licensee and vendor processes ensure LOCA analysis input values for PCT-sensitive parameters bound the as-operated plant values for those parameters
   - (For PWRs) The models and procedures continue to comply with 10 CFR 50.46 during the switchover from the refueling water storage tank to the containment sump (i.e., the core remains adequately cool during any flow reduction or interruption that may occur during switchover).
   - (For PWRs) Large-break LOCA analyses account for boric acid buildup during long-term core cooling and that the predicted time to initiate hot leg injection is consistent with the times in the operating procedures.
   - (For BWRs) The licensee's comparison of parameters used in the LOCA analysis with actual core design parameters provide the needed justification to confirm the applicability of the generic LOCA methodology.

10. The ATWS review is conducted to ensure that the plant meets the 10 CFR 50.62 requirements:

    - For PWR plants with both a diverse scram system (DSS) and ATWS mitigation system actuation circuitry (AMSAC), the staff will not review ATWS for EPUs.
    - For PWR plants where a DSS is not specifically required by 10 CFR 50.62, a review is conducted to verify that the consequences of an ATWS are acceptable. The acceptance criteria is that the peak primary system pressure should not exceed the ASME Service Level C limit of 3200 psig. The peak ATWS pressure is primarily a function of the moderator temperature coefficient and the primary system relief capacity.

- For BWR plants, the review is conducted to ensure that the licensee has appropriately accounted for changes in analyses due to the uprated power level and confirm that required equipment, such as the standby liquid control system (SLCS) pumps, can deliver required flowrates. The review will also cover the SLCS relief valve margin. In addition, a review is conducted to ensure that SLCS flow can be injected at the assumed time without lifting bypass relief valves during the limiting ATWS.

HCGS NOTES - MATRIX 8

SE 2.8.1, Fuel System Design. The fuel design is described in the Cycle 13 and EPU Mixed Core Analysis Report, the Cycle 13 and EPU Fuel Transition Reports and the CLTP and EPU SAFER/GESTR Reports.

SE 2.8.2, Nuclear Design. The core design is described in the Cycle 13 and EPU Mixed Core Analysis Report, the Cycle 13 and EPU Fuel Transition Reports, the CLTP and EPU SAFER/GESTR Reports and the Cycle 13 and EPU BSP, DIVOM and OPTIII reports. Future core designs will be performed on a cycle specific basis and the characteristics of specific core designs are evaluated during the reload licensing analysis.

SE 2.8.3, Thermal and Hydraulic Design. Thermal Hydraulic design of the core is core/fuel dependent and is performed and validated a cycle specific basis in the reload licensing analysis. The thermal hydraulic design is described in the Thermal Hydraulic Compatibility Report, the Cycle 13 and EPU Mixed Core Analysis Report, the Cycle 13 and EPU Fuel Transition Reports and the Cycle 13 and EPU BSP, DIVOM and Option III reports.

SE 2.8.4.2, Over pressure Protection During Power Operation. The adequacy of the pressure relief system is also demonstrated by the overpressure protection evaluation performed for each reload core and by the ATWS evaluation performed for CPPU.

SE 2.8.4.5, Standby Liquid Control System. The HCGS Standby Liquid Control System is designed to actuate automatically. SLC system performance is addressed in the Cycle 13 and EPU Mixed Core Analysis Report and the Cycle 13 and EPU Fuel Transition Reports.

SE 2.8.5.1, Decrease in Feedwater Temperature/Increase in Feedwater Flow. Transients are also analyzed in Cycle 13 and EPU Mixed Core Analysis Report and the Cycle 13 and EPU Fuel Transition Reports

SE 2.8.5.2.1, Loss of External Load; Turbine Trip, Loss of Condenser Vacuum; Closure of MSIV. Transients are also analyzed in Cycle 13 and EPU Mixed Core Analysis Report and the Cycle 13 and EPU Fuel Transition Reports

SE 2.8.5.2.2, Loss of Non-Emergency AC Power to Station Auxiliaries. Transients are also analyzed in Cycle 13 and EPU Fuel Transition Reports.

SE 2.8.5.2.3, Loss of Normal Feedwater Flow. Transients are also analyzed in Cycle 13 and EPU Fuel Transition Reports

SE 2.8.5.3.2, Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break. Transients are also analyzed in Cycle 13 and EPU Mixed Core Analysis Report and the Cycle 13 and EPU Fuel Transition Reports

SE 2.8.5.4.1, Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition. Continuous Rod Withdrawal during a reactor startup from a subcritical or low power startup condition is described in Hope Creek UFSAR Section 15.4.1.2 and UFSAR Appendix 15B. As described in the UFSAR, the low power rod withdrawal error events are considered as non-limiting events, and are not reanalyzed as part of the reload analysis unless the event disposition changes.

The analysis of the transient caused by continuous control rod withdrawal in the startup range described in UFSAR Appendix 15B demonstrates considerable margin for the peak fuel enthalpy for both GE and SVEA fuel to the licensing basis criterion of 170 cal/gm.

Section 2.4 of the NRC Staff Position concerning NEDC-32424P-A (ELTR1) states that only the limiting transients need be included in the uprate amendment request, but a list of all transients analyzed in support of power uprate should be included. The minimum list of events to be included in the power uprate evaluation in ELTR1 Table E-1 is intended to confirm that the existing set of reload analysis transients remain valid for power uprate. The rod withdrawal event identified as a transient to be evaluated for power uprate in ELTR1 Table E-1 is the Rod Withdrawal Error (RWE) at power. Evaluation of the RWE at power is discussed in PUSAR sections 5.3.5 and 9.1, PUSAR Table 9-2, and the Cycle 13 and EPU Mixed Core Analysis Report.

SE 2.8.5.4.2, Uncontrolled Control Rod Withdrawl at Power. Analyses also contained in Cycle 13 and EPU Mixed Core Analysis Report.

SE 2.8.5.4.3, Startup of an Inactive Loop or Recirc Loop at an Incorrect Temperature. Analyses also contained in Cycle 13 and EPU Mixed Core Analysis Report and the Cycle 13 and EPU Fuel Transition Reports

SE 2.8.5.4.4, Spectrum of Rod Drop Accidents. Guidance of R.G. 1.183 is used to evaluate consequences of rod drop accidents as required by AST License Amendment 134. Analyses also contained in Cycle 13 and EPU Mixed Core Analysis Report and the Cycle 13 and EPU Fuel Transition Reports.

SE 2.8.5.5, Inadvertent Operation of ECCS or Malfunction that Increases Reactor Coolant Inventory. Transients are also analyzed in Cycle 13 and EPU Mixed Core Analysis Report

SE 2.8.5.6.2, Emergency Core Cooling System. (LOCA Resulting from Spectrum of Postulated Pipe Breaks). LOCA analysis and the ECCS performance are also addressed in the CLTP and EPU SAFER/GESTR Reports.

SE 2.8.5.7, Anticipated Transients Without Scram. Transients are also analyzed in Cycle 13 and EPU Mixed Core Analysis Report and the Cycle 13 and EPU Fuel Transition Reports.

SE 2.8.6.1, New Fuel Storage. The HCGS EPU submittal does not request approval for a new fuel design.

SE 2.8.6.2, Spent Fuel Storage. The HCGS EPU submittal does not request approval for a new fuel design.

MATRIX 9

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Source Terms and Radiological Consequences Analyses

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Source Terms for Input into Radwaste Management Systems Analyses	All EPUs	SPSB		11.1 Draft Rev. 3 April 1996	10 CFR Part 20 10 CFR Part 50, App. I GDC-60		2.9.1	2.9.1	8.1, 8.3 & 8.4
Radiological Consequence Analyses Using Alternative Source Terms	EPUs that utilize alternative source term	SPSB	EEIB EMCB EMEB IEPB SPLB SRXB	15.0.1 Rev. 0 July 2000	10 CFR 50.67 GDC-19 10 CFR 50.49 10 CFR Part 51 10 CFR Part 50, App. E NUREG-0737		2.9.2	2.9.2	9.2 HCGS NOTE
Radiological Consequences of Main Steamline Failures Outside Containment for a PWR	PWR EPUs that do not utilize alternative source term whose main steamline break analyses result in fuel failure	SPSB	SRXB	15.1.5, App. A Draft Rev. 3 April 1996	10 CFR Part 100	Notes 4, 5, 6, 7, 27*		2.9.2	NA for BWRs
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Radiological Consequences of Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break	EPUs that do not utilize alternative source term whose reactor coolant pump rotor seizure or reactor coolant pump shaft break results in fuel failure	SPSB	SRXB	15.3.3-4 Draft Rev. 3 April 1996	10 CFR Part 100	Notes 5, 8, 9, 27*		2.9.3	NA for BWRs
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			
Radiological Consequences of a Control Rod Ejection Accident	PWR EPUs that do not utilize alternative source term whose rod ejection accident results in fuel failure or melting	SPSB	SRXB	15.4.8, App. A Draft Rev. 2 April 1996	10 CFR Part 100	Notes 4, 21, 22, 27*		2.9.4	NA for BWRs
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			
Radiological Consequences of Control Rod Drop Accident	BWR EPUs that do not utilize alternative source term whose control rod drop accident results in fuel failure or melting	SPSB	SRXB	15.4.9, App. A Draft Rev. 3 April 1996	10 CFR Part 100	Notes 9, 10, 27*	2.9.2		9.2 (Table 9-7) HCGS NOTE
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			
Radiological Consequences of the Failure of Small Lines Carrying Primary	EPUs that do not utilize alternative source term	SPSB		15.6.2 Draft Rev. 3 April 1996	GDC-55 10 CFR Part 100		2.9.3	2.9.5	9.2 (Table 9-4) HCGS NOTE

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Coolant Outside Containment	whose failure of small lines carrying primary coolant outside containment result in fuel failure			6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			
Radiological Consequences of Steam Generator Tube Failure	PWR EPUs that do not utilize alternative source term whose steam generator tube failure results in fuel failure	SPSB	SRXB	15.6.3 Draft Rev. 3 April 1996	10 CFR Part 100	Notes 4, 13, 14, 15, 27*		2.9.6	NA for BWRs
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			
Radiological Consequences of Main Steamline Failure Outside Containment for a BWR	BWR EPUs that do not utilize alternative source term whose main steam line failure outside containment results in fuel failure	SPSB	SRXB	15.6.4 Draft Rev. 3 April 1996	10 CFR Part 100	Note 27*	2.9.4		9.2 (Table 9-3) HCGS NOTE
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			
Radiological Consequences of a Design Basis Loss-Of-Coolant-Accident Including Containment Leakage Contribution	EPUs that do not utilize alternative source term	SPSB	SPLB	15.6.5, App. A Draft Rev. 2 April 1996	10 CFR Part 100	Notes 4, 23, 24, 25, 26, 27*	2.9.5	2.9.7	9.2 (Table 9-5) HCGS NOTE
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Radiological Consequences of a Design Basis Loss-Of-Coolant-Accident: Leakage from ESF Components Outside Containment	EPUs that do not utilize alternative source term	SPSB	SPLB	15.6.5, App. B Draft Rev. 2 April 1996	10 CFR Part 100	Notes 11, 27*	2.9.5	2.9.7	9.2 (Table 9-3) HCGS NOTE
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			
Radiological Consequences of a Design Basis Loss-Of-Coolant-Accident: Leakage from Main Steam Isolation Valves	BWR EPUs that do not utilize alternative source term	SPSB		15.6.5, App. D Draft Rev. 2 April 1996	10 CFR Part 100	Notes 9, 12, 27*	2.9.5		4.6 & 9.2 (Table 9-3) HCGS NOTE
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			
Radiological Consequences of Fuel Handling Accidents	EPUs that do not utilize alternative source term	SPSB	SPLB	15.7.4 Draft Rev. 2 April 1996	10 CFR Part 100 GDC-61	Notes 4, 5, 18, 19, 20, 27*	2.9.6	2.9.8	9.2 (Table 9-4) HCGS NOTE
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			
Radiological Consequences of Spent Fuel Cask Drop Accidents	EPUs that do not utilize alternative source term	SPSB	EMEB SPLB	15.7.5 Draft Rev. 3 April 1996	10 CFR Part 100 GDC-61	Notes, 5, 16, 17, 8, 18, 27*	2.9.7	2.9.9	HCGS UFSAR 9.1 HCGS NOTE
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*			

Notes:

1. In addition to SRP Section 15.6.5, Appendices A, B, and D, dose consequences in the control room are determined from design-basis accidents as part of the review for SRP Sections 15.0.1; 15.1.5, Appendix A; 15.3.3-4, 15.4.8, Appendix A; 15.4.9, Appendix A; 15.6.2, 15.6.3, 15.6.4, 15.7.4, and 15.7.5.

2. Regulatory Guide 1.95 was canceled. Relevant guidance from Regulatory Guide 1.95 was incorporated into Regulatory Guide 1.78, Revision 1 in January 2002. Therefore, Regulatory Guide 1.95 should not be used.

3. Table 6.4-1, attached to SRP Section 6.4 and referred to in Item 7, "Independent Analyses," of the "Review Procedures" Section of SRP Section 6.4 may not be used.

4. Acceptable dose conversion factors may be taken from Table 2.1 of Federal Guidance Report 11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion," Environmental Protection Agency, 1988; and Table III.1 of Federal Guidance Report 12, " External Exposure to Radionuclides in Air, Water, and Soil," Environmental Protection Agency, 1993.

5. NUREG-1465 should not be used.

6. For the review of the main steamline failure accident, review of facilities licensed with, or applying for, alternative repair criteria (ARC) should use SRP Section 15.1.5, Appendix A, in conjunction with the guidance in Draft Regulatory Guide DG-1074, "Steam Generator Tube Integrity," December 1998, for acceptable assumptions and methodologies for performing radiological analyses.

7. For facilities that implement ARC, the primary-to-secondary leak rate in the faulted generator should be assumed to be the maximum accident-induced leakage derived from the repair criteria and burst correlations. The leak rate limiting condition for operation specified in the technical specifications is equally apportioned among the unaffected steam generators.

8. Guidance for the radiological consequences analyses review with respect to acceptable modeling of the radioactivity transport is given in SRP Section 15.6.3, "Radiological Consequences of Steam Generator Tube Failure (PWR)," for applicants that use the traditional source term, based on TID-14844.

9. References to specific computer codes (e.g., SARA, TACT, Pipe Model) are not necessary since other computer codes/methods may be used.

10. In the second paragraph of Section III, "Review Procedure," it is stated that the control rod drop accident is expected to result in radiological consequences less than 10 percent of the 10 CFR Part 100 guideline values, even with conservative assumptions. The value of 10 percent should be replaced with 25 percent.

11. In Section III, "Review Procedures," the guidance in the fourth paragraph, which deals with passive failures, should not be used.

12. The last paragraph on page 15.6.5-4 refers to a "code" developed by J. E. Cline and Associates, Inc. This is identified as Reference 5 in the paragraph. The word "code" should be changed to "model" because the staff does not have the computer code. In addition, the correct reference to the work by J. E. Cline and Associates, Inc., is 4.

13. Item 4 of the "Review Interfaces" section should be deleted. SPSB review of the steam generator tube rupture accidents for their contribution to plant risk is not currently used in the design-basis accident review for radiological consequences.

14. The reference to Figure 3.4-1 of the Nuclear Steam Supply System vendor Standard Technical Specification in Item 6.(a) of Section III, "Review Procedures," does not apply. In addition, the primary coolant iodine concentration discussed in this Item is the 48-hour maximum value.

15. In Item 6.(b) of Section III, "Review Procedures," the multiplier of 500 used for estimating the increase in iodine release rate is reduced to 335 as a result of the staff's review of iodine release rate data collected by Adams and Atwood.

16. The reference to SRP Section 9.1.4 in Item 2.c of the "Review Interfaces" section should be changed to SRP Section 9.1.5.

17. The reference to Regulatory Guide 1.25, which was deleted in 1996, should be retained, with exceptions as noted below in Note 18.

18. The following exceptions to Regulatory Guide 1.25 are provided. These exceptions are based on the staff's review of NUREG/CR-6703.

The fraction of the core inventory assumed to be in the gap for the various nuclides are given in the table below. The release fractions from the table are used in conjunction with the calculated fission product inventory and the maximum core radial peaking factor. These release fractions have been determined to be acceptable for use with currently approved LWR fuel with a peak burnup up to 62,000 MWD/MTU, provided that the maximum linear heat generation rate will not exceed 6.3 kW/ft peak rod average power for rods with burnups that exceed 54 GWD/MTU. As an alternative, fission gas release calculations using NRC-approved methodologies may be considered on a case-by-case basis.

NON-LOCA FRACTION OF FISSION PRODUCT INVENTORY IN GAP	
GROUP	FRACTION
I-131	0.08
Kr-85	0.10
Other Noble Gases	0.05
Other Iodines	0.05

19. References to the Standard Technical Specifications should be replaced with references to the plant-specific technical specifications or technical requirements manual (TRM).

20. Technical Specification Task Force (TSTF) Traveler TSTF-51 proposed to add the term "recently," as it applies to irradiated fuel, to the applicability section of certain technical specifications. The proposed change is intended to remove certain technical specifications requirements for operability of ESF systems (e.g., secondary containment isolation and filtration systems) during refueling. The associated technical specifications bases define "recently," as it applies to irradiated fuel, as the minimum decay time used in supporting radiological consequences analyses of fuel handling accidents. Radiological consequences analyses for these applicants should generally assume a 2-hour release directly to the environment, without holdup or mitigation by ESF systems and no credit for containment closure. Additionally, licensees adding the term "recently" must make a commitment for a single normal or contingency method to promptly close primary or secondary containment penetrations. Such prompt methods need not completely block the penetration or be capable of resisting pressure. The review of this commitment and the prompt methods should be coordinated with IORB, SPLB, and IEPB.

21. In the last sentence of Item 2 of the "Review Interfaces" section, the reference to the number of fuel pins experiencing departure from nucleate boiling (DNB) should be deleted. The reference to fuel clad melting should be used and is therefore retained.

22. In Item 2 of the "Review Procedures" section, the references to the "number of fuel pins reaching DNB" should be deleted and replaced with "the number of fuel pins with cladding failure." In addition, the use of a conservative value of 10 percent for fuel cladding failure in the calculation of the radiological consequences of the rod ejection accident is acceptable.

23. In Item 1 of the "Areas of Review" section, the use of the word "established" is incorrect. The word "established" should be replaced with the word "assessed."

24. In Item 1 of the "Acceptance Criteria" section, the following text in the last line should be deleted: "3.0 Sv (300 rem) to the thyroid and 0.25 Sv (25 rem) to the whole body."

25. In Item 1 of the "Review Procedures" section, the following should be added after the first sentence:

    Appendix K to 10 CFR Part 50 defines conservative analysis assumptions for evaluation of ECCS performance during design-basis LOCAs. Appendix K requires the licensees to assume that the reactor has been operating continuously at a power level at least 1.02 times the licensed power level to allow for instrumentation error. Appendix K allows for an assumed power level less than 1.02 times the licensed power level but not less than the licensed power level, provided the alternative value has been demonstrated to account for uncertainties due to power level instrumentation error.

26. In Item 2 of the "Review Procedures" section, the following statements should be deleted:

    "A check is made of the LOCA [loss-of-coolant accident] assumptions listed in Chapter 15 of the SAR to verify that the primary containment leakage rate has been assumed to remain constant over the course of the accident for a BWR and to remain constant at one half of the initial leak rate after 24 hours for a PWR."

    "The leakage rate used should correspond to that given in the technical specification."

The above statements should be replaced with the following:

    "A check is made of the LOCA assumptions listed in Chapter 15 of the SAR to verify acceptable primary containment leakage assumptions. The primary containment should be assumed to leak at the peak pressure technical specification leak rate for the first 24 hours. For PWRs, the leakage rate may be reduced after the first 24 hours to 50 percent of the TS leak rate. For BWRs, leakage may be reduced after the first 24 hours, if supported by plant configuration and analyses, to a value not less than 50 percent of the TS leak rate. Leakage from subatmospheric containments is assumed to terminate when the containment is brought to and maintained at a subatmospheric condition, as defined by the TSs."

27. The staff has drafted updated guidance on performing design-basis radiological analyses in draft Regulatory Guide DG-1113, "Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents at Light-Water Nuclear Power Reactors," issued for public comment January 2002. The resulting final regulatory guide may be used for guidance on review of design-basis accident non-alternative source term radiological analyses after the date of issuance of the final regulatory guide.

28. In Section II, "Acceptance Criteria," the discussion for Item C related to GDC-19 should be supplemented with

    "and providing a suitably controlled environment for the control room operators and the equipment located therein."

29. In Section II, Item 2, "Ventilation System Criteria," the discussion related to review of the control room area ventilation system under SRP Section 9.4.1 should be retained.

HCGS NOTES - MATRIX 9

SE 2.9.2, Radiological Consequence Analysis Using Alternative Source Terms. NRC approved HCGS License Amendment 134 authorizing full scope implementation of Alternative Source Term methodology at HCGS.

SE 2.9.2, Radiological Consequences of Control Rod Drop Accident (CRDA). RS-001 Matrix 9 states that the review criterion is applicable to EPU's that do not utilize AST. NRC approved full scope implementation of the Alternative Source Term methodology iaw License Amendment 134. HCGS analyzed CRDA using the guidance in Regulatory Guide 1.183, Appendix C.

SE 2.9.3, Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment. RS-001 Matrix 9 states that the review criterion is applicable to EPU's that do not utilize AST. NRC approved full scope implementation of the Alternative Source Term methodology iaw License Amendment 134 HCGS analyzed this DBA using TEDE dose criteria for the EAB, LPZ and CR.

SE 2.9.4, Radiological Consequences of Main Steamline Failure Outside Containment for a BWR. RS-001 Matrix 9 states that the review criterion is applicable to EPU's that do not utilize AST. NRC approved full scope implementation of the Alternative Source Term methodology iaw License Amendment 134. HCGS analyzed this DBA using the guidance in RG 1.183, Appendix D.

SE 2.9.5, ESF Components Outside Containment: RS-001 Matrix 9 states that the review criterion is applicable to EPU's that do not utilize AST. NRC approved full scope implementation of the Alternative Source Term methodology iaw License Amendment 134. HCGS analyzed this post-LOCA release path using the guidance in RG 1.183, Appendix A.

SE 2.9.5, a Design Basis LOCA: Leakage from Main Steam Isolation Valves. RS-001 Matrix 9 states that the review criterion is applicable to EPU's that do not utilize AST. NRC approved full scope implementation of the Alternative Source Term methodology iaw License Amendment 134. HCGS analyzed this post LOCA release path using the guidance of RG 1.183, Appendix A. The NRC approved an increase in the allowable leakage from Main Steam Isolation Valves and removal of the MSIV Leakage Control System.

SE 2.9.6, Radiological Consequences of Fuel Handling Accidents. RS-001 Matrix 9 states that the review criterion is applicable to EPU's that do not utilize AST. NRC approved full scope implementation of the Alternative Source Term

methodology iaw License Amendment 134. HCGS analyzed the FHA using the guidance of RG 1.183 Appendix B.

SE 2.9.7, Radiological Consequences of Spent Fuel Cask Drop Accidents. RS-001 Matrix 9 states that the review criterion is applicable to EPU's that do not utilize AST. NRC approved HCGS License Amendment 134 authorizing full scope implementation of the Alternative Source Term methodology for HCGS. Additionally, HCGS utilizes a single failure proof crane and specially designed lifting devices meeting ANSI N14.6 to perform all heavy load lifts. All heavy load lifts are controlled in accordance with the requirements of NUREG 0612 and the HCGS Heavy Load Control Program. Therefore a SFP Cask Drop is not analyzed.

MATRIX 10

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Health Physics

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Radiation Sources	All EPUs	IEPB		12.2 Draft Rev. 3 April 1996	10 CFR Part 20		2.10.1	2.10.1	8.3 & 8.4
Radiation Protection Design Features	All EPUs	IEPB		12.3-4 Draft Rev. 3 April 1996	10 CFR Part 20 GDC-19	Note 1*	2.10.1	2.10.1	8.5 & 8.6
Operational Radiation Protection Program	All EPUs	IEPB		12.5 Draft Rev. 3 April 1996	10 CFR Part 20	Note 2* Note 3*	2.10.1	2.10.1	8.5

Notes:

1. Regulatory Guide 8.12, "Criticality Accident Alarm Systems" has been withdrawn and should not be used.
2. Regulatory Guide 8.3, "Film Badge Performance Criteria" has been withdrawn and should not be used.
3. Regulatory Guide 8.14, "Personnel Neutron Dosimeters" has been withdrawn and should not be used.

MATRIX 11

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Human Performance

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Reactor Operator Training	All EPUs	IROB		13.2.1* Draft Rev. 2 Dec. 2002	Specific review questions are provided in the template safety evaluations.		2.11	2.11	10.6
Training for Non-Licensed Plant Staff	All EPUs	IROB		13.2.2* Draft Rev. 2 Dec. 2002	Specific review questions are provided in the template safety evaluations.		2.11	2.11	10.6 HCGS NOTE
Operating and Emergency Operating Procedures	All EPUs	IROB	SPLB SPSB SRXB	13.5.2.1* Draft Rev. 1 Dec. 2002	Specific review questions are provided in the template safety evaluations.		2.11	2.11	10.6 & 10.9
Human Factors Engineering	All EPUs	IROB		18.0** Draft Rev. 0 April 1996	Specific review questions are provided in the template safety evaluations.		2.11	2.11	10.6

*The staff is currently finalizing SRP Sections 13.2.1, 13.2.2, and 13.5.2.1. While these SRP Sections are being finalized, the staff will continue to use the versions issued in December 2002 for interim use and public comment. Once finalized, the staff will use the new versions of these SRP Sections.

**The staff received significant comment on draft SRP Chapter 18.0 that was issued in December 2002 for interim use and public comment. The staff is working on finalizing this SRP. However, due to the significance of the comments received, the staff will use Draft SRP Chapter 18.0, Revision 0, dated April 1996.

HCGS NOTES - MATRIX 11

SE 2.11, Training for Non-Licensed Plant Staff. PSEG Nuclear configuration change control procedures require that each change implemented thru a design change, a procedure change or a license amendment be reviewed for training needs. These training needs analyses will address non-licensed personnel training needs consistent with the requirements of 10 CFR 50.120.

MATRIX 12

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Power Ascension and Testing Plan

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	Cross Reference to CPPU SAR
Power Ascension and Testing	All EPUs	IEPB	EEIB EMCB EMEB IROB SPLB SPSB SRXB	14.2.1* Draft Rev. 0 Dec. 2002	Entire Section		2.12	2.12	10.4 HCGS NOTE

*The staff is currently finalizing SRP Section 14.2.1. While this SRP Section is being finalized, the staff will continue to use the version issued for interim use and public comment in December 2002. Once finalized, the staff will use the new version.

HCGS NOTES - MATRIX 12

SE 2.12, Power Ascension and Testing. Additional information is provided in Attachment 6 to the License Change Request.

MATRIX 13

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Risk Evaluation

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Acceptance Review Checklist
							BWR	PWR	
Risk Evaluation	All EPUs	SPSB				Note 1* RG 1.174 RIS 2001-02	2.13	2.13	10.5 HCGS NOTE

Notes:
1. The staff's review is based on Attachment 1 to this matrix. Attachment 1 invokes SRP Chapter 19, Appendix D, if special circumstances are identified during the review.

HCGS NOTES - MATRIX 13

SE 2.13, Risk Evaluation. Additional information is provided in Attachment 14 to the License Change Request.

HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE

This Attachment provides markups of the NRC Review Standard RS-001 template safety evaluation inserts to aid the NRC staff in preparing the safety evaluation for the Hope Creek extended power uprate.

INSERT 1

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Material Surveillance Program

Regulatory Evaluation

Note: NRC approved HCGS License Amendment 151, dated July 23,2004 which revised the reactor vessel surveillance program to follow the BWRVIP Integrated Surveillance Program as the basis for meeting 10CFR50 Appendix H requirements.

The reactor vessel material surveillance program provides a means for determining and monitoring the fracture toughness of the reactor vessel beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the reactor vessel. The NRC staff's review primarily focused on the effects of the proposed EPU on the licensee's reactor vessel surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on (1) General Design Criterion (GDC)-14, insofar as it requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (2) GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the reactor vessel beltline region; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix H. Specific review criteria are contained in Standard Review Plan (SRP) Section 5.3.1 and other guidance provided in Matrix 1 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the reactor vessel surveillance withdrawal schedule and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the schedule. The NRC staff further concludes that the reactor vessel capsule withdrawal schedule is appropriate to ensure that the material surveillance program will continue to meet the requirements of 10 CFR Part 50, Appendix H, and 10 CFR 50.60, and will provide the licensee with information to ensure continued compliance with GDC-14 and GDC-31 in this respect following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the reactor vessel material surveillance program.

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

Regulatory Evaluation

Note: NRC approved License Amendment 157, dated November 1, 2004, which revised the Reactor Vessel Pressure –Temperature Limits and extended their validity to 32 effective full power years.

Pressure-temperature (P-T) limits are established to ensure the structural integrity of the ferritic components of the RCPB during any condition of normal operation, including anticipated operational occurrences and hydrostatic tests. The NRC staff's review of P-T limits covered the P-T limits methodology and the calculations for the number of effective full power years specified for the proposed EPU, considering neutron embrittlement effects and using linear elastic fracture mechanics. The NRC's acceptance criteria for P-T limits are based on (1) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (2) GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix G. Specific review criteria are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the P-T limits for the plant and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the P-T limits. The NRC staff further concludes that the licensee has demonstrated the validity of the proposed P-T limits for operation under the proposed EPU conditions. Based on this, the NRC staff concludes that the proposed P-T limits will continue to meet the requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.60 and will enable the licensee to comply with GDC-14 and GDC-31 in this respect following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the proposed P-T limits.

2.1.3 Reactor Internal and Core Support Materials

Regulatory Evaluation

The reactor internals and core supports include structures, systems, and components (SSCs) that perform safety functions or whose failure could affect safety functions performed by other SSCs. These safety functions include reactivity monitoring and control, core cooling, and fission product confinement (within both the fuel cladding and the reactor coolant system (RCS)). The NRC staff's review covered the materials' specifications and mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation. The NRC's acceptance criteria for reactor internal and core support materials are based on GDC-1 and 10 CFR 50.55a for material specifications, controls on welding, and inspection of reactor internals and core supports. Specific review criteria are contained in SRP Section 4.5.2 and Boiling Water Reactor Vessel and Internals Project (BWRVIP)-26.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of reactor internal and core support materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in operating temperature and neutron fluence on the integrity of reactor internal and core support materials. The NRC staff further concludes that the licensee has demonstrated that the reactor internal and core support materials will continue to be acceptable and will continue to meet the requirements of GDC-1 and 10 CFR 50.55a with respect to material specifications, welding controls, and inspection following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to reactor internal and core support materials.

2.1.4 Reactor Coolant Pressure Boundary Materials

Regulatory Evaluation

The RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The NRC staff's review of RCPB materials covered their specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs. The NRC's acceptance criteria for RCPB materials are based on (1) 10 CFR 50.55a and GDC-1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (3) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (4) GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (5) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB. Specific review criteria are contained in SRP Section 5.2.3 and other guidance provided in Matrix 1 of RS-001. Additional review guidance for primary water stress-corrosion cracking (PWSCC) of dissimilar metal welds and associated inspection programs is contained in Generic Letter (GL) 97-01, Information Notice (IN) 00-17, Bulletin (BL) 01-01, BL 02-01, and BL 02-02. Additional review guidance for thermal embrittlement of cast austenitic stainless steel components is contained in a letter from C. Grimes, NRC, to D. Walters, Nuclear Energy Institute (NEI), dated May 19, 2000.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RCPB materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of RCPB materials. The NRC staff further concludes that the licensee has demonstrated that the RCPB materials will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of GDC-1, GDC-4, GDC-14, GDC-31, 10 CFR Part 50, Appendix G, and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed EPU acceptable with respect to RCPB materials.

2.1.5 Protective Coating Systems (Paints) - Organic Materials

Regulatory Evaluation

Protective coating systems (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides and also provide wear protection during plant operation and maintenance activities. The NRC staff's review covered protective coating systems used inside the containment for their suitability for and stability under design-basis loss-of-coolant accident (DBLOCA) conditions, considering radiation and chemical effects. The NRC's acceptance criteria for protective coating systems are based on (1) 10 CFR Part 50, Appendix B, which states quality assurance requirements for the design, fabrication, and construction of safety-related SSCs and (2) Regulatory Guide 1.54, Revision 1, for guidance on application and performance monitoring of coatings in nuclear power plants. Specific review criteria are contained in SRP Section 6.1.2.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on protective coating systems and concludes that the licensee has appropriately addressed the impact of changes in conditions following a DBLOCA and their effects on the protective coatings. The NRC staff further concludes that the licensee has demonstrated that the protective coatings will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of 10 CFR Part 50, Appendix B. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protective coatings systems.

2.1.6 Flow-Accelerated Corrosion

Regulatory Evaluation

Flow-accelerated corrosion (FAC) is a corrosion mechanism occurring in carbon steel components exposed to flowing single- or two-phase water. Components made from stainless steel are immune to FAC, and FAC is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on velocity of flow, fluid temperature, steam quality, oxygen content, and pH. During plant operation, control of these parameters is limited and the optimum conditions for minimizing FAC effects, in most cases, cannot be achieved. Loss of material by FAC will, therefore, occur. The NRC staff has reviewed the effects of the proposed EPU on FAC and the adequacy of the licensee's FAC program to predict the rate of loss so that repair or replacement of damaged components could be made before they reach critical thickness. The licensee's FAC program is based on NUREG-1344, GL 89-08, and the guidelines in Electric Power Research Institute (EPRI) Report NSAC-202L-R2. It consists of predicting loss of material using the CHECWORKS computer code, and visual inspection and volumetric examination of the affected components. The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusions

The NRC staff has reviewed the licensee's evaluation of the effect of the proposed EPU on the FAC analysis for the plant and concludes that the licensee has adequately addressed changes in the plant operating conditions on the FAC analysis. The NRC staff further concludes that the licensee has demonstrated that the updated analyses will predict the loss of material by FAC and will ensure timely repair or replacement of degraded components following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to FAC.

2.1.7 Reactor Water Cleanup System

Regulatory Evaluation

The reactor water cleanup system (RWCS) provides a means for maintaining reactor water quality by filtration and ion exchange and a path for removal of reactor coolant when necessary. Portions of the RWCS comprise the RCPB. The NRC staff's review of the RWCS included component design parameters for flow, temperature, pressure, heat removal capability, and impurity removal capability; and the instrumentation and process controls for proper system operation and isolation. The review consisted of evaluating the adequacy of the plant's TSs in these areas under the proposed EPU conditions. The NRC's acceptance criteria for the RWCS are based on (1) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (2) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (3) GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement. Specific review criteria are contained in SRP Section 5.4.8.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the RWCS and concludes that the licensee has adequately addressed changes in impurity levels and pressure and their effects on the RWCS. The NRC staff further concludes that the licensee has demonstrated that the RWCS will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of GDC-14, GDC-60, and GDC-61. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RWCS.

[2.1.8 <u>Additional Review Areas</u> (Materials and Chemical Engineering)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 2

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

SSCs important to safety could be impacted by the pipe-whip dynamic effects of a pipe rupture. The NRC staff conducted a review of pipe rupture analyses to ensure that SSCs important to safety are adequately protected from the effects of pipe ruptures. The NRC staff's review covered (1) the implementation of criteria for defining pipe break and crack locations and configurations, (2) the implementation of criteria dealing with special features, such as augmented inservice inspection (ISI) programs or the use of special protective devices such as pipe-whip restraints, (3) pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects, and (4) the design adequacy of supports for SSCs provided to ensure that the intended design functions of the SSCs will not be impaired to an unacceptable level as a result of pipe-whip or jet impingement loadings. The NRC staff's review focused on the effects that the proposed EPU may have on items (1) thru (4) above. The NRC's acceptance criteria are based on GDC-4, which requires SSCs important to safety to be designed to accommodate the dynamic effects of a postulated pipe rupture. Specific review criteria are contained in SRP Section 3.6.2.

Note: PSEG received NRC approval to eliminate arbitrary intermediate pipe breaks from consideration in performing these evaluations in NRC's SER HCGS SSER No. 5, Appendix O, "NRC Safety Evaluation for the Elimination of Arbitrary Intermediate Pipe Breaks", dated April 1986.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluations related to determinations of rupture locations and associated dynamic effects and concludes that the licensee has adequately addressed the effects of the proposed EPU on them. The NRC staff further concludes that the licensee has demonstrated that SSCs important to safety will continue to meet the requirements of GDC-4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the determination of rupture locations and dynamic effects associated with the postulated rupture of piping.

2.2.2 Pressure-Retaining Components and Component Supports

Regulatory Evaluation

The NRC staff has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code* (B&PV Code), Section III, Division 1, and GDCs 1, 2, 4, 14, and 15. The NRC staff's review focused on the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. The NRC staff's review covered (1) the analyses of flow-induced vibration and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and cumulative fatigue usage factors (CUFs) against the code-allowable limits. The NRC's acceptance criteria are based on (1) 10 CFR 50.55a and GDC-1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (4) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (5) GDC-15, insofar as it requires that the RCS be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1; and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

Nuclear Steam Supply System Piping, Components, and Supports

[Insert technical evaluation for nuclear steam supply system (NSSS) piping, components, and supports. Include an intermediate conclusion in the form of "Because [summarize reasons], the NSSS piping, components, and supports are adequate under the proposed EPU conditions."]

Balance-of-Plant Piping, Components, and Supports

[Insert technical evaluation for balance-of-plant piping, components, and supports. Include an intermediate conclusion in the form of "Because [summarize reasons], the balance-of-plant piping, components, and supports are adequate under the proposed EPU conditions."]

Reactor Vessel and Supports

[Insert technical evaluation for reactor vessel and supports. Include an intermediate conclusion in the form of "Because [summarize reasons], the reactor vessel and supports are adequate under the proposed EPU conditions."]

Control Rod Drive Mechanism

[Insert technical evaluation for control rod drive mechanism. Include an intermediate conclusion in the form of "Because [summarize reasons], the control rod drive mechanism is adequate under the proposed EPU conditions."]

Recirculation Pumps and Supports

[Insert technical evaluation for reactor coolant pumps and supports. Include an intermediate conclusion in the form of "Because [summarize reasons], the recirculation pumps and supports are adequate under the proposed EPU conditions."]

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of pressure-retaining components and their supports. For the reasons set forth above, the NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these components and their supports. Based on the above, the NRC staff further concludes that the licensee has demonstrated that pressure-retaining components and their supports will continue to meet the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

2.2.3 Reactor Pressure Vessel Internals and Core Supports

Regulatory Evaluation

Reactor pressure vessel internals consist of all the structural and mechanical elements inside the reactor vessel, including core support structures. The NRC staff reviewed the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for the reactor internals for normal operation, upset, emergency, and faulted conditions. These include pressure differences and thermal effects for normal operation, transient pressure loads associated with loss-of-coolant accidents (LOCAs), and the identification of design transient occurrences. The NRC staff's review covered (1) the analyses of flow-induced vibration for safety-related and non-safety-related reactor internal components and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and CUFs against the corresponding Code-allowable limits. The NRC's acceptance criteria are based on (1) 10 CFR 50.55a and GDC-1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; and (4) GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5; and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of reactor internals and core supports and concludes that the licensee has adequately addressed the effects of the proposed EPU on the reactor internals and core supports. The NRC staff further concludes that the licensee has demonstrated that the reactor internals and core supports will continue to meet the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, and GDC-10 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the design of the reactor internal and core supports.

2.2.4 Safety-Related Valves and Pumps

Regulatory Evaluation

NRC Letter, "HCGS Implementation of a Risk Informed Inservice Inspection Program" and associated SER , dated December 8, 2004 authorized implementation of a risk Informed ISI program in accordance with Reg. Guide 1.178.

The NRC's staff's review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME B&PV Code and within the scope of Section XI of the ASME B&PV Code and the ASME Operations and Maintenance (O&M) Code, as applicable. The NRC staff's review focused on the effects of the proposed EPU on the required functional performance of the valves and pumps. The review also covered any impacts that the proposed EPU may have on the licensee's motor-operated valve (MOV) programs related to GL 89-10, GL 96-05, and GL 95-07. The NRC staff also evaluated the licensee's consideration of lessons learned from the MOV program and the application of those lessons learned to other safety-related power-operated valves. The NRC's acceptance criteria are based on (1) GDC-1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-37, GDC-40, GDC-43, and GDC-46, insofar as they require that the emergency core cooling system (ECCS), the containment heat removal system, the containment atomospheric cleanup systems, and the cooling water system, respectively, be designed to permit appropriate periodic testing to ensure the leak-tight integrity and performance of their active components; (3) GDC-54, insofar as it requires that piping systems penetrating containment be designed with the capability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits; and (4) 10 CFR 50.55a(f), insofar as it requires that pumps and valves subject to that section must meet the inservice testing program requirements identified in that section. Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6; and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps and concludes that the licensee has adequately addressed the effects of the proposed EPU on safety-related pumps and valves. The NRC staff further concludes that the licensee has adequately evaluated the effects of the proposed EPU on its MOV programs related to GL 89-10, GL 96-05, and GL 95-07, and the lessons learned from those programs to other safety-related, power-operated valves. Based on this, the NRC staff concludes that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of GDC-1, GDC-37, GDC-40, GDC-43, GDC-46, GDC-54, and 10 CFR 50.55a(f) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to safety-related valves and pumps.

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

Regulatory Evaluation

Mechanical and electrical equipment covered by this section includes equipment associated with systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal. Equipment associated with systems essential to preventing significant releases of radioactive materials to the environment are also covered by this section. The NRC staff's review focused on the effects of the proposed EPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated pipe-whip and jet impingement forces. The primary input motions due to the safe shutdown earthquake (SSE) are not affected by an EPU. The NRC's acceptance criteria are based on (1) GDC-1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-30, insofar as it requires that components that are part of the RCPB be designed, fabricated, erected, and tested to the highest quality standards practical; (3) GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (4) 10 CFR Part 100, Appendix A, which sets forth the principal seismic and geologic considerations for the evaluation of the suitability of plant design bases established in consideration of the seismic and geologic characteristics of the plant site; (5) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (6) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (7) 10 CFR Part 50, Appendix B, which sets quality assurance requirements for safety-related equipment. Specific review criteria are contained in SRP Section 3.10.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluations of the effects of the proposed EPU on the qualification of mechanical and electrical equipment and concludes that the licensee has (1) adequately addressed the effects of the proposed EPU on this equipment and (2) demonstrated that the equipment will continue to meet the requirements of GDCs 1, 2, 4, 14, and 30; 10 CFR Part 100, Appendix A; and 10 CFR Part 50, Appendix B, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the qualification of the mechanical and electrical equipment.

[2.2.6 Additional Review Areas (Mechanical and Civil Engineering)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 3

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

Regulatory Evaluation

Environmental qualification (EQ) of electrical equipment involves demonstrating that the equipment is capable of performing its safety function under significant environmental stresses which could result from DBAs. The NRC staff's review focused on the effects of the proposed EPU on the environmental conditions that the electrical equipment will be exposed to during normal operation, anticipated operational occurrences, and accidents. The NRC staff's review was conducted to ensure that the electrical equipment will continue to be capable of performing its safety functions following implementation of the proposed EPU. The NRC's acceptance criteria for EQ of electrical equipment are based on 10 CFR 50.49, which sets forth requirements for the qualification of electrical equipment important to safety that is located in a harsh environment. Specific review criteria are contained in SRP Section 3.11.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EQ of electrical equipment and concludes that the licensee has adequately addressed the effects of the proposed EPU on the environmental conditions for and the qualification of electrical equipment. The NRC staff further concludes that the electrical equipment will continue to meet the relevant requirements of 10 CFR 50.49 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EQ of electrical equipment.

2.3.2 Offsite Power System

Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the offsite power system; and the stability studies for the electrical transmission grid. The NRC staff's review focused on whether the loss of the nuclear unit, the largest operating unit on the grid, or the most critical transmission line will result in the loss of offsite power (LOOP) to the plant following implementation of the proposed EPU. The NRC's acceptance criteria for offsite power systems are based on GDC-17. Specific review criteria are contained in SRP Sections 8.1 and 8.2, Appendix A to SRP Section 8.2, and Branch Technical Positions (BTPs) PSB-1 and ICSB-11.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the offsite power system and concludes that the offsite power system will continue to meet the requirements of GDC-17 following implementation of the proposed EPU. Adequate physical and electrical separation exists and the offsite power system has the capacity and capability to supply power to all safety loads and other required equipment. The NRC staff further concludes that the impact of the proposed EPU on grid stability is insignificant. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the offsite power system.

2.3.3 AC Onsite Power System

Regulatory Evaluation

The alternating current (ac) onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems provided to supply power to safety-related equipment. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the ac onsite power system. The NRC's acceptance criteria for the ac onsite power system are based on GDC-17, insofar as it requires the system to have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions. Specific review criteria are contained in SRP Sections 8.1 and 8.3.1.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ac onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The NRC staff further concludes that the ac onsite power system will continue to meet the requirements of GDC-17 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ac onsite power system.

2.3.4 DC Onsite Power System

Regulatory Evaluation

The direct current (dc) onsite power system includes the dc power sources and their distribution and auxiliary supporting systems that are provided to supply motive or control power to safety-related equipment. The NRC staff's review covered the information, analyses, and referenced documents for the dc onsite power system. The NRC's acceptance criteria for the dc onsite power system are based on GDC-17, insofar as it requires the system to have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions. Specific review criteria are contained in SRP Sections 8.1 and 8.3.2

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the dc onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The NRC staff further concludes that the dc onsite power system will continue to meet the requirements of GDC-17 following implementation of the proposed EPU. Adequate physical and electrical separation exists and the system has the capacity and capability to supply power to all safety loads and other required equipment. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the dc onsite power system.

2.3.5 Station Blackout

Regulatory Evaluation

Station blackout (SBO) refers to a complete loss of ac electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the LOOP concurrent with a turbine trip and failure of the onsite emergency ac power system. SBO does not include the loss of available ac power to buses fed by station batteries through inverters or the loss of power from "alternate ac sources" (AACs). The NRC staff's review focused on the impact of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC's acceptance criteria for SBO are based on 10 CFR 50.63. Specific review criteria are contained in SRP Sections 8.1 and Appendix B to SRP Section 8.2; and other guidance provided in Matrix 3 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC staff concludes that the licensee has adequately evaluated the effects of the proposed EPU on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to SBO.

[2.3.6 Additional Review Areas (Electrical Engineering)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 4

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.4 Instrumentation and Controls

2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

Regulatory Evaluation

Instrumentation and control systems are provided (1) to control plant processes having a significant impact on plant safety, (2) to initiate the reactivity control system (including control rods), (3) to initiate the engineered safety features (ESF) systems and essential auxiliary supporting systems, and (4) for use to achieve and maintain a safe shutdown condition of the plant. Diverse instrumentation and control systems and equipment are provided for the express purpose of protecting against potential common-mode failures of instrumentation and control protection systems. The NRC staff conducted a review of the reactor trip system, engineered safety feature actuation system (ESFAS), safe shutdown systems, control systems, and diverse instrumentation and control systems for the proposed EPU to ensure that the systems and any changes necessary for the proposed EPU are adequately designed such that the systems continue to meet their safety functions. The NRC staff's review was also conducted to ensure that failures of the systems do not affect safety functions. The NRC's acceptance criteria related to the quality of design of protection and control systems are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and GDCs 1, 4, 13, 19, 20, 21, 22, 23, and 24. Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's application related to the effects of the proposed EPU on the functional design of the reactor trip system, ESFAS, safe shutdown system, and control systems. The NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these systems and that the changes that are necessary to achieve the proposed EPU are consistent with the plant's design basis. The NRC staff further concludes that the systems will continue to meet the requirements of 10 CFR 50.55a(a)(1), 10 CFR 50.55(a)(h), and GDCs 1, 4, 13, 19, 20, 21, 22, 23, and 24. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to instrumentation and controls.

[2.4.2 Additional Review Areas (Instrumentation and Controls)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 5

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.5 Plant Systems

2.5.1 Internal Hazards

2.5.1.1 Flooding

2.5.1.1.1 Flood Protection

Regulatory Evaluation

The NRC staff conducted a review in the area of flood protection to ensure that SSCs important to safety are protected from flooding. The NRC staff's review covered flooding of SSCs important to safety from internal sources, such as those caused by failures of tanks and vessels. The NRC staff's review focused on increases of fluid volumes in tanks and vessels assumed in flooding analyses to assess the impact of any additional fluid on the flooding protection that is provided. The NRC's acceptance criteria for flood protection are based on GDC-2. Specific review criteria are contained in SRP Section 3.4.1.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the proposed changes in fluid volumes in tanks and vessels for the proposed EPU. The NRC staff concludes that SSCs important to safety will continue to be protected from flooding and will continue to meet the requirements of GDC-2 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to flood protection.

2.5.1.1.2 Equipment and Floor Drains

Regulatory Evaluation

The function of the equipment and floor drainage system (EFDS) is to assure that waste liquids, valve and pump leakoffs, and tank drains are directed to the proper area for processing or disposal. The EFDS is designed to handle the volume of leakage expected, prevent a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment, and protect against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system. The NRC staff's review of the EFDS included the collection and disposal of liquid effluents outside containment.
The NRC staff's review focused on any changes in fluid volumes or pump capacities that are necessary for the proposed EPU and are not consistent with previous assumptions with respect to floor drainage considerations. The NRC's acceptance criteria for the EFDS are based on GDCs 2 and 4 insofar as they require the EFDS to be designed to withstand the effects of earthquakes and to be compatible with the environmental conditions (flooding) associated with normal operation, maintenance, testing, and postulated accidents (pipe failures and tank ruptures). Specific review criteria are contained in SRP Section 9.3.3.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EFDS and concludes that the licensee has adequately accounted for the plant changes resulting in increased water volumes and larger capacity pumps or piping systems. The NRC staff concludes that the EFDS has sufficient capacity to (1) handle the additional expected leakage resulting from the plant changes, (2) prevent the backflow of water to areas with safety-related equipment, and (3) ensure that contaminated fluids are not transferred to noncontaminated drainage systems. Based on this, the NRC staff concludes that the EFDS will continue to meet the requirements of GDCs 2 and 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EFDS.

2.5.1.1.3 Circulating Water System

Regulatory Evaluation

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems. The NRC staff's review of the CWS focused on changes in flooding analyses that are necessary due to increases in fluid volumes or installation of larger capacity pumps or piping needed to accommodate the proposed EPU. The NRC's acceptance criteria for the CWS are based on GDC-4 for the effects of flooding of safety-related areas due to leakage from the CWS and the effects of malfunction or failure of a component or piping of the CWS on the functional performance capabilities of safety-related SSCs. Specific review criteria are contained in SRP Section 10.4.5.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the modifications to the CWS and concludes that the licensee has adequately evaluated these modifications. The NRC staff concludes that, consistent with the requirements of GDC-4, the increased volumes of fluid leakage that could potentially result from these modifications would not result in the failure of safety-related SSCs following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CWS.

2.5.1.2 Missile Protection

2.5.1.2.1. Internally Generated Missiles

Regulatory Evaluation

The NRC staff's review concerns missiles that could result from in-plant component overspeed failures and high-pressure system ruptures. The NRC staff's review of potential missile sources covered pressurized components and systems, and high-speed rotating machinery. The NRC staff's review was conducted to ensure that safety-related SSCs are adequately protected from internally generated missiles. In addition, for cases where safety-related SSCs are located in areas containing non-safety-related SSCs, the NRC staff reviewed the non-safety-related SSCs to ensure that their failure will not preclude the intended safety function of the safety-related SSCs. The NRC staff's review focused on any increases in system pressures or component overspeed conditions that could result during plant operation, anticipated operational occurrences, or changes in existing system configurations such that missile barrier considerations could be affected. The NRC's acceptance criteria for the protection of SSCs important to safety against the effects of internally generated missiles that may result from equipment failures are based on GDC-4. Specific review criteria are contained in SRP Sections 3.5.1.1 and 3.5.1.2.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the changes in system pressures and configurations that are required for the proposed EPU and concludes that SSCs important to safety will continue to be protected from internally generated missiles and will continue to meet the requirements of GDC-4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to internally generated missiles.

2.5.1.2.2 Turbine Generator

Regulatory Evaluation

The turbine control system, steam inlet stop and control valves, low pressure turbine steam intercept and inlet control valves, and extraction steam control valves control the speed of the turbine under normal and abnormal conditions, and are thus related to the overall safe operation of the plant. The NRC staff's review of the turbine generator focused on the effects of the proposed EPU on the turbine overspeed protection features to ensure that a turbine overspeed condition above the design overspeed is very unlikely. The NRC's acceptance criteria for the turbine generator are based on GDC-4, and relates to protection of SSCs important to safety from the effects of turbine missiles by providing a turbine overspeed protection system (with suitable redundancy) to minimize the probability of generating turbine missiles. Specific review criteria are contained in SRP Section 10.2.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the turbine generator and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on turbine overspeed. The NRC staff concludes that the turbine generator will continue to provide adequate turbine overspeed protection to minimize the probability of generating turbine missiles and will continue to meet the requirements of GDC-4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the turbine generator.

2.5.1.3 Pipe Failures

Regulatory Evaluation

The NRC staff conducted a review of the plant design for protection from piping failures outside containment to ensure that (1) such failures would not cause the loss of needed functions of safety-related systems and (2) the plant could be safely shut down in the event of such failures. The NRC staff's review of pipe failures included high and moderate energy fluid system piping located outside of containment. The NRC staff's review focused on the effects of pipe failures on plant environmental conditions, control room habitability, and access to areas important to safe control of postaccident operations where the consequences are not bounded by previous analyses. The NRC's acceptance criteria for pipe failures are based on GDC-4, which requires, in part, that SSCs important to safety be designed to accommodate the dynamic effects of postulated pipe ruptures, including the effects of pipe whipping and discharging fluids. Specific review criteria are contained in SRP Section 3.6.1.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the changes that are necessary for the proposed EPU and the licensee's proposed operation of the plant, and concludes that SSCs important to safety will continue to be protected from the dynamic effects of postulated piping failures in fluid systems outside containment and will continue to meet the requirements of GDC-4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protection against postulated piping failures in fluid systems outside containment.

2.5.1.4 Fire Protection

Regulatory Evaluation

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment. The NRC staff's review focused on the effects of the increased decay heat on the plant's safe shutdown analysis to ensure that SSCs required for the safe shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe shutdown following a fire. The NRC's acceptance criteria for the FPP are based on (1) 10 CFR 50.48 and associated Appendix R to 10 CFR Part 50, insofar as they require the development of an FPP to ensure, among other things, the capability to safely shut down the plant; (2) GDC-3, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; (3) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions. Specific review criteria are contained in SRP Section 9.5.1, as supplemented by the guidance provided in Attachment 2 to Matrix 5 of Section 2.1 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's fire-related safe shutdown assessment and concludes that the licensee has adequately accounted for the effects of the increased decay heat on the ability of the required systems to achieve and maintain safe shutdown conditions. The NRC staff further concludes that the FPP will continue to meet the requirements of 10 CFR 50.48, Appendix R to 10 CFR Part 50, and GDCs 3 and 5 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to fire protection.

2.5.2 Fission Product Control

2.5.2.1 Fission Product Control Systems and Structures

Regulatory Evaluation

The NRC staff's review for fission product control systems and structures covered the basis for developing the mathematical model for DBLOCA dose computations, the values of key parameters, the applicability of important modeling assumptions, and the functional capability of ventilation systems used to control fission product releases. The NRC staff's review primarily focused on any adverse effects that the proposed EPU may have on the assumptions used in the analyses for control of fission products. The NRC's acceptance criteria are based on GDC-41, insofar as it requires that the containment atmosphere cleanup system be provided to reduce the concentration of fission products released to the environment following postulated accidents. Specific review criteria are contained in SRP Section 6.5.3.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on fission product control systems and structures. The NRC staff concludes that the licensee has adequately accounted for the increase in fission products and changes in expected environmental conditions that would result from the proposed EPU. The NRC staff further concludes that the fission product control systems and structures will continue to provide adequate fission product removal in postaccident environments following implementation of the proposed EPU. Based on this, the NRC staff also concludes that the fission product control systems and structures will continue to meet the requirements of GDC-41. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fission product control systems and structures.

2.5.2.2 Main Condenser Evacuation System

Regulatory Evaluation

The main condenser evacuation system (MCES) generally consists of two subsystems: (1) the "hogging" or startup system which initially establishes main condenser vacuum and (2) the system which maintains condenser vacuum once it has been established. The NRC staff's review focused on modifications to the system that may affect gaseous radioactive material handling and release assumptions, and design features to preclude the possibility of an explosion (if the potential for explosive mixtures exists). The NRC's acceptance criteria for the MCES are based on (1) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) GDC-64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences and postulated accidents. Specific review criteria are contained in SRP Section 10.4.2.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of required changes to the MCES and concludes that the licensee has adequately evaluated these changes. The NRC staff concludes that the MCES will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment following implementation of the proposed EPU. The NRC also concludes that the MCES will continue meet the requirements of GDCs 60 and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MCES.

2.5.2.3 Turbine Gland Sealing System

Regulatory Evaluation

The turbine gland sealing system is provided to control the release of radioactive material from steam in the turbine to the environment. The NRC staff reviewed changes to the turbine gland sealing system with respect to factors that may affect gaseous radioactive material handling (e.g., source of sealing steam, system interfaces, and potential leakage paths). The NRC's acceptance criteria for the turbine gland sealing system are based on (1) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) GDC-64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences and postulated accidents. Specific review criteria are contained in SRP Section 10.4.3.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of required changes to the turbine gland sealing system and concludes that the licensee has adequately evaluated these changes. The NRC staff concludes that the turbine gland sealing system will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment consistent with GDCs 60 and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the turbine gland sealing system.

2.5.2.4 Main Steam Isolation Valve Leakage Control System

Regulatory Evaluation

~~Redundant quick-acting isolation valves are provided on each main steamline. The leakage control system is designed to reduce the amount of direct, untreated leakage from the main steam isolation valves (MSIVs) when isolation of the primary system and containment is required. The NRC staff's review of the MSIV leakage control system focused on the effects of the proposed EPU on the amount of leakage assumed to occur. The NRC's acceptance criteria for the MSIV leakage control system are based on GDC-54, insofar as it requires that piping systems penetrating containment be provided with leakage detection and isolation capabilities. Specific review criteria are contained in SRP Section 6.7.~~

License Amendment 134 authorized removal of the MSIV Leakage Control System, therefore HCGS does not use this system.

~~Technical Evaluation~~

~~[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]~~

~~Conclusion~~

~~The NRC staff has reviewed the licensee's assessment related to the MSIV leakage control system and finds that the licensee has adequately accounted for the effects of the proposed EPU on the assumed leakage through the MSIVs. The NRC staff further concludes that the leakage control system will continue to reliably detect and isolate the leakage, as required by GDC-54. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MSIV leakage control system.~~

2.5.3 Component Cooling and Decay Heat Removal

2.5.3.1 Spent Fuel Pool Cooling and Cleanup System

Regulatory Evaluation

The spent fuel pool provides wet storage of spent fuel assemblies. The safety function of the spent fuel pool cooling and cleanup system is to cool the spent fuel assemblies and keep the spent fuel assemblies covered with water during all storage conditions. The NRC staff's review for the proposed EPU focused on the effects of the proposed EPU on the capability of the system to provide adequate cooling to the spent fuel during all operating and accident conditions. The NRC's acceptance criteria for the spent fuel pool cooling and cleanup system are based on (1) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions, (2) GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and (3) GDC-61, insofar as it requires that fuel storage systems be designed with RHR capability reflecting the importance to safety of decay heat removal, and measures to prevent a significant loss of fuel storage coolant inventory under accident conditions. Specific review criteria are contained in SRP Section 9.1.3, as supplemented by the guidance provided in Attachment 1 to Matrix 5 of Section 2.1 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to the spent fuel pool cooling and cleanup system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the spent fuel pool cooling function of the system. Based on this review, the NRC staff concludes that the spent fuel pool cooling and cleanup system will continue to provide sufficient cooling capability to cool the spent fuel pool following implementation of the proposed EPU and will continue to meet the requirements of GDCs 5, 44, and 61. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the spent fuel pool cooling and cleanup system.

2.5.3.2 Station Service Water System

Regulatory Evaluation

The station service water system (SWS) provides essential cooling to safety-related equipment and may also provide cooling to non-safety-related auxiliary components that are used for normal plant operation. The NRC staff's review covered the characteristics of the station SWS components with respect to their functional performance as affected by adverse operational (i.e., water hammer) conditions, abnormal operational conditions, and accident conditions (e.g., a LOCA with the LOOP). The NRC staff's review focused on the additional heat load that would result from the proposed EPU. The NRC's acceptance criteria are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, including flow instabilities and loads (e.g., water hammer), maintenance, testing, and postulated accidents; (2) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.1, as supplemented by GL 89-13 and GL 96-06.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the station SWS and concludes that the licensee has adequately accounted for the increased heat loads on system performance that would result from the proposed EPU. The NRC staff concludes that the station SWS will continue to be protected from the dynamic effects associated with flow instabilities and provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU. Therefore, the NRC staff has determined that the station SWS will continue to meet the requirements of GDCs 4, 5, and 44. Based on the above, the NRC staff finds the proposed EPU acceptable with respect to the station SWS.

2.5.3.3 Reactor Auxiliary Cooling Water Systems

Regulatory Evaluation

The NRC staff's review covered reactor auxiliary cooling water systems that are required for (1) safe shutdown during normal operations, anticipated operational occurrences, and mitigating the consequences of accident conditions, or (2) preventing the occurrence of an accident. These systems include closed-loop auxiliary cooling water systems for reactor system components, reactor shutdown equipment, ventilation equipment, and components of the ECCS. The NRC staff's review covered the capability of the auxiliary cooling water systems to provide adequate cooling water to safety-related ECCS components and reactor auxiliary equipment for all planned operating conditions. Emphasis was placed on the cooling water systems for safety-related components (e.g., ECCS equipment, ventilation equipment, and reactor shutdown equipment). The NRC staff's review focused on the additional heat load that would result from the proposed EPU. The NRC's acceptance criteria for the reactor auxiliary cooling water system are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation including flow instabilities and attendant loads (i.e., water hammer), maintenance, testing, and postulated accidents; (2) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.2, as supplemented by GL 89-13 and GL 96-06.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the reactor auxiliary cooling water systems and concludes that the licensee has adequately accounted for the increased heat loads from the proposed EPU on system performance. The NRC staff concludes that the reactor auxiliary cooling water systems will continue to be protected from the dynamic effects associated with flow instabilities and provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU. Therefore, the NRC staff has determined that the reactor auxiliary cooling water systems will continue to meet the requirements of GDCs 4, 5, and 44. Based on the above, the NRC staff finds the proposed EPU acceptable with respect to the reactor auxiliary cooling water systems.

2.5.3.4 Ultimate Heat Sink

Regulatory Evaluation

The ultimate heat sink (UHS) is the source of cooling water provided to dissipate reactor decay heat and essential cooling system heat loads after a normal reactor shutdown or a shutdown following an accident. The NRC staff's review focused on the impact that the proposed EPU has on the decay heat removal capability of the UHS. Additionally, the NRC staff's review included evaluation of the design-basis UHS temperature limit determination to confirm that post-licensing data trends (e.g., air and water temperatures, humidity, wind speed, water volume) do not establish more severe conditions than previously assumed. The NRC's acceptance criteria for the UHS are based on (1) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety; and (2) GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.5.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the information that was provided by the licensee for addressing the effects that the proposed EPU would have on the UHS safety function, including the licensee's validation of the design-basis UHS temperature limit based on post-licensing data. Based on the information that was provided, the NRC staff concludes that the proposed EPU will not compromise the design-basis safety function of the UHS, and that the UHS will continue to satisfy the requirements of GDCs 5 and 44 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the UHS.

2.5.4 Balance-of-Plant Systems

2.5.4.1. Main Steam

Regulatory Evaluation

The main steam supply system (MSSS) transports steam from the NSSS to the power conversion system and various safety-related and non-safety-related auxiliaries. The NRC staff's review focused on the effects of the proposed EPU on the system's capability to transport steam to the power conversion system, provide heat sink capacity, supply steam to drive safety system pumps, and withstand adverse dynamic loads (e.g., water steam hammer resulting from rapid valve closure and relief valve fluid discharge loads). The NRC's acceptance criteria for the MSSS are based on (1) GDC-4, insofar as it requires that SSCs important to safety be protected against dynamic effects, including the effects missiles, pipe whip, and jet impingement forces associated with pipe breaks; and (2) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions. Specific review criteria are contained in SRP Section 10.3.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the MSSS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MSSS. The NRC staff concludes that the MSSS will maintain its ability to transport steam to the power conversion system, provide heat sink capacity, supply steam to steam-driven safety pumps, and withstand steam hammer. The NRC staff further concludes that the MSSS will continue to meet the requirements of GDCs 4 and 5. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MSSS.

2.5.4.2 Main Condenser

Regulatory Evaluation

The main condenser (MC) system is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system (TBS). For BWRs without an MSIV leakage control system, the MC system may also serve an accident mitigation function to act as a holdup volume for the plateout of fission products leaking through the MSIVs following core damage. The NRC staff's review focused on the effects of the proposed EPU on the steam bypass capability with respect to load rejection assumptions, and on the ability of the MC system to withstand the blowdown effects of steam from the TBS. The NRC's acceptance criteria for the MC system are based on GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 10.4.1.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the MC system and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MC system. The NRC staff concludes that the MC system will continue to maintain its ability to withstand the blowdown effects of the steam from the TBS and thereby continue to meet GDC-60 with respect to controlling releases of radioactive effluents. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MC system.

2.5.4.3 Turbine Bypass

Regulatory Evaluation

The TBS is designed to discharge a stated percentage of rated main steam flow directly to the MC system, bypassing the turbine. This steam bypass enables the plant to take step-load reductions up to the TBS capacity without the reactor or turbine tripping. The system is also used during startup and shutdown to control reactor pressure. For a BWR without an MSIV leakage control system, the TBS could also provide an accident mitigation function. A TBS, along with the MSSS and MC system, may be credited for mitigating the effects of MSIV leakage during a LOCA by the holdup and plateout of fission products. The NRC staff's review for the TBS focused on the effects that the proposed EPU have on load rejection capability, analysis of postulated system piping failures, and the consequences of inadvertent TBS operation. The NRC's acceptance criteria for the TBS are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents (including pipe breaks or malfunctions of the TBS), and (2) GDC-34, insofar as it requires that a RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core at a rate such that SAFDLs and the design conditions of the RCPB are not exceeded. Specific review criteria are contained in SRP Section 10.4.4.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the TBS. The NRC staff concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the TBS. The NRC staff concludes that the TBS will continue to mitigate the effects of MSIV leakage during a LOCA and provide a means for shutting down the plant during normal operations. The NRC staff further concludes that TBS failures will not adversely affect essential SSCs. Based on this, the NRC staff concludes that the TBS will continue to meet GDCs 4 and 34. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the TBS.

2.5.4.4 Condensate and Feedwater

Regulatory Evaluation

The condensate and feedwater system (CFS) provides feedwater at a particular temperature, pressure, and flow rate to the reactor. The only part of the CFS classified as safety-related is the feedwater piping from the NSSS up to and including the outermost containment isolation valve. The NRC staff's review focused on how the proposed EPU affects previous analyses and considerations with respect to the capability of the CFS to supply adequate feedwater during plant operation and shutdown, and isolate components, subsystems, and piping in order to preserve the system's safety function. The NRC's acceptance criteria for the CFS are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation including possible fluid flow instabilities (e.g., water hammer), maintenance, testing, and postulated accidents; (2) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and that the system be provided with suitable isolation capabilities to assure the safety function can be accomplished with electric power available from only the onsite system or only the offsite system, assuming a single failure. Specific review criteria are contained in SRP Section 10.4.7.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the CFS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the CFS. The NRC staff concludes that the CFS will continue to maintain its ability to satisfy feedwater requirements for normal operation and shutdown, withstand water hammer, maintain isolation capability in order to preserve the system safety function, and not cause failure of safety-related SSCs. The NRC staff further concludes that the CFS will continue to meet the requirements of GDCs 4, 5, and 44. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CFS.

2.5.5 Waste Management Systems

2.5.5.1 Gaseous Waste Management Systems

Regulatory Evaluation

The gaseous waste management systems involve the gaseous radwaste system, which deals with the management of radioactive gases collected in the offgas system or the waste gas storage and decay tanks. In addition, it involves the management of the condenser air removal system; the gland seal exhaust and the mechanical vacuum pump operation exhaust; and the building ventilation system exhausts. The NRC staff's review focused on the effects that the proposed EPU may have on (1) the design criteria of the gaseous waste management systems, (2) methods of treatment, (3) expected releases, (4) principal parameters used in calculating the releases of radioactive materials in gaseous effluents, and (5) design features for precluding the possibility of an explosion if the potential for explosive mixtures exists. The NRC's acceptance criteria for gaseous waste management systems are based on (1) 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC-3, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; (3) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (4) GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (5) 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" (ALARA) criterion. Specific review criteria are contained in SRP Section 11.3.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to the gaseous waste management systems. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of gaseous waste on the abilities of the systems to control releases of radioactive materials and preclude the possibility of an explosion if the potential for explosive mixtures exists. The NRC staff finds that the gaseous waste management systems will continue to meet their design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the gaseous waste management systems will continue to meet the requirements of 10 CFR 20.1302; GDCs 3, 60, and 61; and 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the gaseous waste management systems.

2.5.5.2 Liquid Waste Management Systems

Regulatory Evaluation

The NRC staff's review for liquid waste management systems focused on the effects that the proposed EPU may have on previous analyses and considerations related to the liquid waste management systems' design, design objectives, design criteria, methods of treatment, expected releases, and principal parameters used in calculating the releases of radioactive materials in liquid effluents. The NRC's acceptance criteria for the liquid waste management systems are based on (1) 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (4) 10 CFR Part 50, Appendix I, Sections II.A and II.D, which set numerical guides for dose design objectives and limiting conditions for operation to meet the ALARA criterion. Specific review criteria are contained in SRP Section 11.2.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to the liquid waste management systems. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of liquid waste on the ability of the liquid waste management systems to control releases of radioactive materials. The NRC staff finds that the liquid waste management systems will continue to meet their design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the liquid waste management systems will continue to meet the requirements of 10 CFR 20.1302; GDCs 60 and 61; and 10 CFR Part 50, Appendix I, Sections II.A and II.D. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the liquid waste management systems.

2.5.5.3 Solid Waste Management Systems

Regulatory Evaluation

The NRC staff's review for the solid waste management systems (SWMS) focused on the effects that the proposed EPU may have on previous analyses and considerations related to the design objectives in terms of expected volumes of waste to be processed and handled, the wet and dry types of waste to be processed, the activity and expected radionuclide distribution contained in the waste, equipment design capacities, and the principal parameters employed in the design of the SWMS. The NRC's acceptance criteria for the SWMS are based on (1) 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) GDC-63, insofar as it requires that systems be provided in waste handling areas to detect conditions that may result in excessive radiation levels, (4) GDC-64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs, and postulated accidents; and (5) 10 CFR Part 71, which states requirements for radioactive material packaging. Specific review criteria are contained in SRP Section 11.4.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to the SWMS. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of solid waste on the ability of the SWMS to process the waste. The NRC staff finds that the SWMS will continue to meet its design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the SWMS will continue to meet the requirements of 10 CFR 20.1302, GDCs 60, 63, and 64, and 10 CFR Part 71. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SWMS.

2.5.6 Additional Considerations

2.5.6.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

Regulatory Evaluation

Nuclear power plants are required to have redundant onsite emergency power supplies of sufficient capacity to perform their safety functions (e.g., power diesel engine-driven generator sets), assuming a single failure. The NRC staff's review focused on increases in emergency diesel generator electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function. The NRC's acceptance criteria for the emergency diesel engine fuel oil storage and transfer system are based on (1) GDC-4, insofar as it requires that SSCs important to safety be protected against dynamic effects, including missiles, pipe whip, and jet impingement forces associated with pipe breaks; (2) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC-17, insofar as it requires onsite power supplies to have sufficient independence and redundancy to perform their safety functions, assuming a single failure. Specific review criteria are contained in SRP Section 9.5.4.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to the amount of required fuel oil for the emergency diesel generators and concludes that the licensee has adequately accounted for the effects of the increased electrical demand on fuel oil consumption. The NRC staff concludes that the fuel oil storage and transfer system will continue to provide an adequate amount of fuel oil to allow the diesel generators to meet the onsite power requirements of GDCs 4, 5, and 17. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fuel oil storage and transfer system.

2.5.6.2 Light Load Handling System (Related to Refueling)

Regulatory Evaluation

The light load handling system (LLHS) includes components and equipment used in handling new fuel at the receiving station and the loading of spent fuel into shipping casks. The NRC staff's review covered the avoidance of criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures. The NRC staff's review focused on the effects of the new fuel on system performance and related analyses. The NRC's acceptance criteria for the LLHS are based on (1) GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement and with suitable shielding for radiation protection; and (2) GDC-62, insofar as it requires that criticality be prevented. Specific review criteria are contained in SRP Section 9.1.4.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the new fuel on the ability of the LLHS to avoid criticality accidents and concludes that the licensee has adequately incorporated the effects of the new fuel in the analyses. Based on this review, the NRC staff further concludes that the LLHS will continue to meet the requirements of GDCs 61 and 62 for radioactivity releases and prevention of criticality accidents. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the LLHS.

[2.5.7 Additional Review Areas (Plant Systems)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 6

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.6 Containment Review Considerations

2.6.1 Primary Containment Functional Design

Regulatory Evaluation

The containment encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident. The NRC staff's review for the primary containment functional design covered (1) the temperature and pressure conditions in the drywell and wetwell due to a spectrum of postulated LOCAs, (2) the differential pressure across the operating deck for a spectrum of LOCAs (Mark II containments only), (3) suppression pool dynamic effects during a LOCA or following the actuation of one or more RCS safety/relief valves, (4) the consequences of a LOCA occurring within the containment (wetwell), (5) the capability of the containment to withstand the effects of steam bypassing the suppression pool, (6) the suppression pool temperature limit during RCS safety/relief valve operation, and (7) the analytical models used for containment analysis. The NRC's acceptance criteria for the primary containment functional design are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects; (2) GDC-16, insofar as it requires that reactor containment be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment; (3) GDC-50, insofar as it requires that the containment and its associated heat removal systems be designed so that the containment structure can accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated temperature and pressure conditions resulting from any LOCA; (4) GDC-13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation and for accident conditions, as appropriate, to assure adequate safety; and (5) GDC-64, insofar as it requires that means be provided to monitor the reactor containment atmosphere for radioactivity that may be released from normal operations and from postulated accidents. Specific review criteria are contained in SRP Section 6.2.1.1.C.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the containment temperature and pressure transient and concludes that the licensee has adequately accounted for the increase of mass and energy resulting from the proposed EPU. The NRC staff further concludes that containment systems will continue to provide sufficient pressure and temperature mitigation capability to ensure that containment integrity is maintained. The NRC staff also concludes that containment systems and instrumentation will continue to be adequate for monitoring containment parameters and release of radioactivity during normal and accident conditions and the containment and associated systems will continue to meet the requirements of GDCs 4, 13,

16, 50, and 64 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to primary containment functional design.

2.6.2 Subcompartment Analyses

Regulatory Evaluation

Note: PSEG has submitted a "Request for License Amendment: ARTS/MELLLA Implementation", dated June 7, 2004 which includes calculation of mass and energy releases for the MELLLA condition, including revised annulus pressurization loading methodology which are bounding for CPPU reactor thermal power levels.

A subcompartment is defined as any fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. The NRC staff's review for subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments. The NRC staff's review focused on the effects of the increase in mass and energy release into the containment due to operation at EPU conditions, and the resulting increase in pressurization. The NRC's acceptance criteria for subcompartment analyses are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects, and (2) GDC-50, insofar as it requires that containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments. Specific review criteria are contained in SRP Section 6.2.1.2.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the subcompartment assessment performed by the licensee and the change in predicted pressurization resulting from the increased mass and energy release. The NRC staff concludes that containment SSCs important to safety will continue to be protected from the dynamic effects resulting from pipe breaks and that the subcompartments will continue to have sufficient margins to prevent fracture of the structure due to pressure difference across the walls following implementation of the proposed EPU. Based on this, the NRC staff concludes that the plant will continue to meet GDCs 4 and 50 for the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to subcompartment analyses.

2.6.3 Mass and Energy Release

2.6.3.1 Mass and Energy Release Analysis for Postulated Loss of Coolant

Regulatory Evaluation

The release of high-energy fluid into containment from pipe breaks could challenge the structural integrity of the containment, including subcompartments and systems within the containment. The NRC staff's review covered the energy sources that are available for release to the containment and the mass and energy release rate calculations for the initial blowdown phase of the accident. The NRC's acceptance criteria for mass and energy release analyses for postulated LOCAs are based on (1) GDC-50, insofar as it requires that sufficient conservatism be provided in the mass and energy release analysis to assure that containment design margin is maintained and (2) 10 CFR Part 50, Appendix K, insofar as it identifies sources of energy during a LOCA. Specific review criteria are contained in SRP Section 6.2.1.3.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's mass and energy release assessment and concludes that the licensee has adequately addressed the effects of the proposed EPU and appropriately accounts for the sources of energy identified in 10 CFR Part 50, Appendix K. Based on this, the NRC staff finds that the mass and energy release analysis meets the requirements in GDC-50 for ensuring that the analysis is conservative. Therefore, the NRC staff finds the proposed EPU acceptable with respect to mass and energy release for postulated LOCA.

2.6.4 Combustible Gas Control in Containment

Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the containment due to chemical reactions between the fuel rod cladding and steam, corrosion of aluminum and other materials, and radiolytic decomposition of water. If excessive hydrogen is generated, it may form a combustible mixture in the containment atmosphere. The NRC staff's review covered (1) the production and accumulation of combustible gases, (2) the capability to prevent high concentrations of combustible gases in local areas, (3) the capability to monitor combustible gas concentrations, and (4) the capability to reduce combustible gas concentrations. The NRC staff's review primarily focused on any impact that the proposed EPU may have on hydrogen release assumptions, and how increases in hydrogen release are mitigated. The NRC's acceptance criteria for combustible gas control in containment are based on (1) 10 CFR 50.44, insofar as it requires that plants be provided with the capability for controlling combustible gas concentrations in the containment atmosphere; (2) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; (3) GDC-41, insofar as it requires that systems be provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure that containment integrity is maintained; (4) GDC-42, insofar as it requires that systems required by GDC-41 be designed to permit appropriate periodic inspection; and (5) GDC-43, insofar as it requires that systems required by GDC-41 be designed to permit appropriate periodic testing. ***[Include the following sentence for BWRs with Mark III containments:*** **Additional requirements based on 10 CFR 50.44 for control of combustible gas apply to plants with a Mark III type of containment that do not rely on an inerted atmosphere to control hydrogen inside the containment.]** Specific review criteria are contained in SRP Section 6.2.5.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to combustible gas and concludes that the plant will continue to have sufficient capabilities consistent with the requirements in 10 CFR 50.44 and GDCs 5, 41, 42, and 43 as discussed above. Therefore, the NRC staff finds the proposed EPU acceptable with respect to combustible gas control in containment.

2.6.5 Containment Heat Removal

Regulatory Evaluation

Fan cooler systems, spray systems, and residual heat removal (RHR) systems are provided to remove heat from the containment atmosphere and from the water in the containment wetwell. The NRC staff's review in this area focused on (1) the effects of the proposed EPU on the analyses of the available net positive suction head (NPSH) to the containment heat removal system pumps and (2) the analyses of the heat removal capabilities of the spray water system and the fan cooler heat exchangers. The NRC's acceptance criteria for containment heat removal are based on GDC-38, insofar as it requires that a containment heat removal system be provided, and that its function shall be to rapidly reduce the containment pressure and temperature following a LOCA and maintain them at acceptably low levels. Specific review criteria are contained in SRP Section 6.2.2, as supplemented by Draft Guide (DG) 1107.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the containment heat removal systems assessment provided by the licensee and concludes that the licensee has adequately addressed the effects of the proposed EPU. The NRC staff finds that the systems will continue to meet GDC-38 with respect to rapidly reducing the containment pressure and temperature following a LOCA and maintaining them at acceptably low levels. Therefore, the NRC staff finds the proposed EPU acceptable with respect to containment heat removal systems.

2.6.6 Secondary Containment Functional Design

Regulatory Evaluation

The secondary containment structure and supporting systems of dual containment plants are provided to collect and process radioactive material that may leak from the primary containment following an accident. The supporting systems maintain a negative pressure within the secondary containment and process this leakage. The NRC staff's review covered (1) analyses of the pressure and temperature response of the secondary containment following accidents within the primary and secondary containments; (2) analyses of the effects of openings in the secondary containment on the capability of the depressurization and filtration system to establish a negative pressure in a prescribed time; (3) analyses of any primary containment leakage paths that bypass the secondary containment; (4) analyses of the pressure response of the secondary containment resulting from inadvertent depressurization of the primary containment when there is vacuum relief from the secondary containment; and (5) the acceptability of the mass and energy release data used in the analysis. The NRC staff's review primarily focused on the effects that the proposed EPU may have on the pressure and temperature response and drawdown time of the secondary containment, and the impact this may have on offsite dose. The NRC's acceptance criteria for secondary containment functional design are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and be protected from dynamic effects (e.g., the effects of missiles, pipe whipping, and discharging fluids) that may result from equipment failures; and (2) GDC-16, insofar as it requires that reactor containment and associated systems be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment. Specific review criteria are contained in SRP Section 6.2.3.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to the secondary containment pressure and temperature transient and the ability of the secondary containment to provide an essentially leak-tight barrier against uncontrolled release of radioactivity to the environment. The NRC staff concludes that the licensee has adequately accounted for the increase of mass and energy that would result from the proposed EPU and further concludes that the secondary containment and associated systems will continue to provide an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment following implementation of the proposed EPU. Based on this, the NRC staff also concludes that the secondary containment and associated systems will continue to meet the requirements of GDCs 4 and 16. Therefore, the NRC staff finds the proposed EPU acceptable with respect to secondary containment functional design.

[2.6.7 Additional Review Areas (Containment Review Considerations)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 7

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

Regulatory Evaluation

The NRC staff reviewed the control room habitability system and control building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. A further objective of the NRC staff's review was to ensure that the control room can be maintained as the backup center from which technical support center personnel can safely operate in the case of an accident. The NRC staff's review focused on the effects of the proposed EPU on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination. The NRC's acceptance criteria for the control room habitability system are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with postulated accidents, including the effects of the release of toxic gases; and (2) ~~GDC-19~~ 10CFR50.67, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem ~~whole body, or its equivalent, to any part of the body,~~ TEDE for the duration of the accident. Specific review criteria are contained in SRP Section 6.4 and other guidance provided in Matrix 7 of RS-001.

Note: NRC Approved License Amendment 134 implementing Alternative Source Term. The evaluation and acceptance criteria for the CPPU are derived from 10CFR50.67 and RG 1.183.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the ability of the control room habitability system to protect plant operators against the effects of accidental releases of toxic and radioactive gases. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from the proposed EPU. The NRC staff further concludes that the control room habitability system will continue to provide the required protection following implementation of the proposed EPU. Based on this, the NRC staff concludes that the control room habitability system will continue to meet the requirements of GDC~~s~~ 4 and ~~19~~ 10CFR50.67. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the control room habitability system.

2.7.2 Engineered Safety Feature Atmosphere Cleanup

Regulatory Evaluation

ESF atmosphere cleanup systems are designed for fission product removal in postaccident environments. These systems generally include primary systems (e.g., in-containment recirculation) and secondary systems (e.g., standby gas treatment systems and emergency or postaccident air-cleaning systems) for the fuel-handling building, control room, shield building, and areas containing ESF components. For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed EPU on system functional design, environmental design, and provisions to preclude temperatures in the adsorber section from exceeding design limits. The NRC's acceptance criteria for ESF atmosphere cleanup systems are based on (1) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident; (2) GDC-41, insofar as it requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents; (3) GDC-61, insofar as it requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions; and (4) GDC-64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences (AOOs), and postulated accidents. Specific review criteria are contained in SRP Section 6.5.1.

Note: NRC Approved License Amendment 134 authorizing full scope implementation of the Alternative Source Term methodology for HCGS. The evaluation and acceptance criteria for consequences of accidents are derived from 10CFR50.67 and RG 1.183 and RG 1.52.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESF atmosphere cleanup systems. The NRC staff concludes that the licensee has adequately accounted for the increase of fission products and changes in expected environmental conditions that would result from the proposed EPU, and the NRC staff further concludes that the ESF atmosphere cleanup systems will continue to provide adequate fission product removal in postaccident environments following implementation of the proposed EPU. Based on this, the NRC staff concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of GDCs 19, 41, 61, and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESF atmosphere cleanup systems.

2.7.3 Control Room Area Ventilation System

Regulatory Evaluation

The function of the control room area ventilation system (CRAVS) is to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components during normal operation, AOOs, and DBA conditions. The NRC's review of the CRAVS focused on the effects that the proposed EPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products; and the expected environmental conditions in areas served by the CRAVS. The NRC's acceptance criteria for the CRAVS are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident; and (3) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.1.

Note: NRC Approved License Amendment 134 authorizing full scope implementation of the Alternative Source Term methodology for HCGS. The evaluation and acceptance criteria for consequences of accidents are derived from 10CFR50.67 and RG 1.183 and RG 1.52.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from a DBA under the conditions of the proposed EPU, and associated changes to parameters affecting environmental conditions for control room personnel and equipment. Accordingly, the NRC staff concludes that the CRAVS will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed EPU. The NRC staff also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the CRAVS will continue to meet the requirements of GDCs 4, 19, and 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CRAVS.

2.7.4 Spent Fuel Pool Area Ventilation System

Regulatory Evaluation

The function of the spent fuel pool area ventilation system (SFPAVS) is to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, and control airborne radioactivity in the area during normal operation, AOOs, and following postulated fuel handling accidents. The NRC staff's review focused on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The NRC's acceptance criteria for the SFPAVS are based on (1) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents, and (2) GDC-61, insofar as it requires that systems which contain radioactivity be designed with appropriate confinement and containment. Specific review criteria are contained in SRP Section 9.4.2.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SFPAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's capability to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, control airborne radioactivity in the area, control release of gaseous radioactive effluents to the environment, and provide appropriate containment. Based on this, the NRC staff concludes that the SFPAVS will continue to meet the requirements of GDCs 60 and 61. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SFPAVS.

2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

Regulatory Evaluation

The function of the auxiliary and radwaste area ventilation system (ARAVS) and the turbine area ventilation system (TAVS) is to maintain ventilation in the auxiliary and radwaste equipment and turbine areas, permit personnel access, and control the concentration of airborne radioactive material in these areas during normal operation, during AOOs, and after postulated accidents. The NRC staff's review focused on the effects of the proposed EPU on the functional performance of the safety-related portions of these systems. The NRC's acceptance criteria for the ARAVS and TAVS are based on GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Sections 9.4.3 and 9.4.4.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ARAVS and TAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the capability of these systems to maintain ventilation in the auxiliary and radwaste equipment areas and in the turbine area, permit personnel access, control the concentration of airborne radioactive material in these areas, and control release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the ARAVS and TAVS will continue to meet the requirements of GDC-60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ARAVS and the TAVS.

2.7.6 Engineered Safety Feature Ventilation System

Regulatory Evaluation

The function of the engineered safety feature ventilation system (ESFVS) is to provide a suitable and controlled environment for ESF components following certain anticipated transients and DBAs. The NRC staff's review for the ESFVS focused on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The NRC staff's review also covered (1) the ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESFVS performance; (2) the capability of the ESFVS to circulate sufficient air to prevent accumulation of flammable or explosive gas or fuel-vapor mixtures from components (e.g., storage batteries and stored fuel); and (3) the capability of the ESFVS to control airborne particulate material (dust) accumulation. The NRC's acceptance criteria for the ESFVS are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC-17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of SSCs important to safety; and (3) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.5.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESFVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the ability of the ESFVS to provide a suitable and controlled environment for ESF components. The NRC staff further concludes that the ESFVS will continue to assure a suitable environment for the ESF components following implementation of the proposed EPU. The NRC staff also concludes that the ESFVS will continue to suitably control the release of gaseous radioactive effluents to the environment following implementation of the proposed EPU. Based on this, the NRC staff concludes that the ESFVS will continue to meet the requirements of GDCs 4, 17 and 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESFVS.

[2.7.7 Additional Review Areas (Habitability, Filtration, and Ventilation)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 8

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.8 Reactor Systems

2.8.1 Fuel System Design

Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, end plates, channel boxes, and reactivity control rods. The NRC staff reviewed the fuel system to ensure that (1) the fuel system is not damaged as a result of normal operation and AOOs, (2) fuel system damage is never so severe as to prevent control rod insertion when it is required, (3) the number of fuel rod failures is not underestimated for postulated accidents, and (4) coolability is always maintained. The NRC staff's review covered fuel system damage mechanisms, limiting values for important parameters, and performance of the fuel system during normal operation, AOOs, and postulated accidents. The NRC's acceptance criteria are based on (1) 10 CFR 50.46, insofar as it establishes standards for the calculation of emergency core cooling system (ECCS) performance and acceptance criteria for that calculated performance; (2) GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (3) GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (4) GDC-35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA. Specific review criteria are contained in SRP Section 4.2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the fuel system design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the fuel system and demonstrated that (1) the fuel system will not be damaged as a result of normal operation and AOOs, (2) the fuel system damage will never be so severe as to prevent control rod insertion when it is required, (3) the number of fuel rod failures will not be underestimated for postulated accidents, and (4) coolability will always be maintained. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, GDC-10, GDC-27, and GDC-35 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fuel system design.

2.8.2 Nuclear Design

Regulatory Evaluation

The NRC staff reviewed the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation and anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. The NRC staff's review covered core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC-11, insofar as it requires that the reactor core be designed so that the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity; (3) GDC-12, insofar as it requires that the reactor core be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can be reliably and readily detected and suppressed; (4) GDC-13, insofar as it requires that instrumentation and controls be provided to monitor variables and systems affecting the fission process over anticipated ranges for normal operation, AOOs and accident conditions, and to maintain the variables and systems within prescribed operating ranges; (5) GDC-20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to automatically initiate operation of systems and components important to safety under accident conditions; (6) GDC-25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; (7) GDC-26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; (8) GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (9) GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core. Specific review criteria are contained in SRP Section 4.3 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effect of the proposed EPU on the nuclear design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the nuclear design and has demonstrated that the fuel design limits will not be exceeded during normal or anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. Based on this evaluation and in coordination with the reviews of the fuel system design, thermal and hydraulic design, and transient and accident analyses, the NRC staff concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the applicable requirements of GDCs 10, 11, 12, 13, 20, 25, 26, 27, and 28. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the nuclear design.

2.8.3 Thermal and Hydraulic Design

Regulatory Evaluation

The NRC staff reviewed the thermal and hydraulic design of the core and the RCS to confirm that the design (1) has been accomplished using acceptable analytical methods, (2) is equivalent to or a justified extrapolation from proven designs, (3) provides acceptable margins of safety from conditions which would lead to fuel damage during normal reactor operation and AOOs, and (4) is not susceptible to thermal-hydraulic instability. The review also covered hydraulic loads on the core and RCS components during normal operation and DBA conditions and core thermal-hydraulic stability under normal operation and anticipated transients without scram (ATWS) events. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; and (2) GDC-12, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can reliably and readily be detected and suppressed. Specific review criteria are contained in SRP Section 4.4 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the thermal and hydraulic design of the core and the RCS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the thermal and hydraulic design and demonstrated that the design (1) has been accomplished using acceptable analytical methods, (2) is **[equivalent to or a justified extrapolation from]** proven designs, (3) provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and AOOs, and (4) is not susceptible to thermal-hydraulic instability. The NRC staff further concludes that the licensee has adequately accounted for the effects of the proposed EPU on the hydraulic loads on the core and RCS components. Based on this, the NRC staff concludes that the thermal and hydraulic design will continue to meet the requirements of GDCs 10 and 12 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to thermal and hydraulic design.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System

Regulatory Evaluation

The NRC staff's review covered the functional performance of the control rod drive system (CRDS) to confirm that the system can effect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents. The review also covered the CRDS cooling system to ensure that it will continue to meet its design requirements. The NRC's acceptance criteria are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC-23, insofar as it requires that the protection system be designed to fail into a safe state; (3) GDC-25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; (4) GDC-26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; (5) GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (6) GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core; (7) GDC-29, insofar as it requires that the protection and reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in event of AOOs; and (8) 10 CFR 50.62(c)(3), insofar as it requires that all BWRs have an alternate rod injection (ARI) system diverse from the reactor trip system, and that the ARI system have redundant scram air header exhaust valves. Specific review criteria are contained in SRP Section 4.6.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the functional design of the CRDS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system's ability to effect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents will be maintained following the implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that sufficient cooling exists to ensure the system's design bases will continue to be followed upon implementation of the proposed EPU. Based on this, the NRC staff concludes

that the fuel system and associated analyses will continue to meet the requirements of GDCs 4, 23, 25, 26, 27, 28, and 29, and 10 CFR 50.62(c)(3) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the functional design of the CRDS.

2.8.4.2 Overpressure Protection During Power Operation

Regulatory Evaluation

Overpressure protection for the RCPB during power operation is provided by relief and safety valves and the reactor protection system. The NRC staff's review covered relief and safety valves on the main steamlines and piping from these valves to the suppression pool. The NRC's acceptance criteria are based on (1) GDC-15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (2) GDC-31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during power operation. The NRC staff concludes that the licensee has (1) adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features and (2) demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, the NRC staff concludes that the overpressure protection features will continue to meet GDCs 15 and 31 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to overpressure protection during power operation.

2.8.4.3 Reactor Core Isolation Cooling System

Regulatory Evaluation

The reactor core isolation cooling (RCIC) system serves as a standby source of cooling water to provide a limited decay heat removal capability whenever the main feedwater system is isolated from the reactor vessel. In addition, the RCIC system may provide decay heat removal necessary for coping with a station blackout. The water supply for the RCIC system comes from the condensate storage tank, with a secondary supply from the suppression pool. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the system. The NRC's acceptance criteria are based on (1) GDC-4, insofar as it requires that SSCs important to safety be protected against dynamic effects; (2) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be demonstrated that sharing will not impair its ability to perform its safety function; (3) GDC-29, insofar as it requires that the protection and reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in event of AOOs; (4) GDC-33, insofar as it requires that a system to provide reactor coolant makeup for protection against small breaks in the RCPB be provided so the fuel design limits are not exceeded; (5) GDC-34, insofar as it requires that a residual heat removal system be provided to transfer fission product decay heat and other residual heat from the reactor core at a rate such that SAFDLs and the design conditions of the RCPB are not exceeded; (6) GDC-54, insofar as it requires that piping systems penetrating containment be designed with the capability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits; and (7) 10 CFR 50.63, insofar as it requires that the plant withstand and recover from an SBO of a specified duration. Specific review criteria are contained in SRP Section 5.4.6

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the ability of the RCIC system to provide decay heat removal following an isolation of main feedwater event and a station blackout event and the ability of the system to provide makeup to the core following a small break in the RCPB. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on these events and demonstrated that the RCIC system will continue to provide sufficient decay heat removal and makeup for these events following implementation of the proposed EPU. Based on this, the NRC staff concludes that the RCIC system will continue to meet the requirements of GDCs 4, 5, 29, 33, 34 and 54, and 10 CFR 50.63 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RCIC system.

2.8.4.4 Residual Heat Removal System

Regulatory Evaluation

The RHR system is used to cool down the RCS following shutdown. The RHR system is typically a low pressure system which takes over the shutdown cooling function when the RCS temperature is reduced. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the RHR system to cool the RCS following shutdown and provide decay heat removal. The NRC's acceptance criteria are based on (1) GDC-4, insofar as it requires that SSCs important to safety be protected against dynamic effects; (2) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC-34, which specifies requirements for an RHR system. Specific review criteria are contained in SRP Section 5.4.7 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the RHR system. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the RHR system will maintain its ability to cool the RCS following shutdown and provide decay heat removal. Based on this, the NRC staff concludes that the RHR system will continue to meet the requirements of GDCs 4, 5, and 34 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RHR system.

2.8.4.5 Standby Liquid Control System

Regulatory Evaluation

The standby liquid control system (SLCS) provides backup capability for reactivity control independent of the control rod system. The SLCS functions by injecting a boron solution into the reactor to effect shutdown. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the system to deliver the required amount of boron solution into the reactor. The NRC's acceptance criteria are based on (1) GDC-26, insofar as it requires that two independent reactivity control systems of different design principles be provided, and that one of the systems be capable of holding the reactor subcritical in the cold condition; (2) GDC-27, insofar as it requires that the reactivity control systems have a combined capability, in conjunction with poison addition by the ECCS, to reliably control reactivity changes under postulated accident conditions; and (3) 10 CFR 50.62(c)(4), insofar as it requires that the SLCS be capable of reliably injecting a borated water solution into the reactor pressure vessel at a boron concentration, boron enrichment, and flow rate that provides a set level of reactivity control, and ~~**[DEPENDING ON CONSTRUCTION PERMIT DATE OR ORIGINAL DESIGN]**~~ that the system initiate automatically. Specific review criteria are contained in SRP Section 9.3.5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the SLCS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system will continue to provide the function of reactivity control independent of the control rod system following implementation of the proposed EPU. Based on this, the NRC staff concludes that the SLCS will continue to meet the requirements of GDCs 26 and 27, and 10 CFR 50.62(c)(4) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SLCS.

2.8.5 Accident and Transient Analyses

2.8.5.1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Main Steam Relief or Safety Valve

Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature which increases core reactivity and can lead to a power level increase and a decrease in shutdown margin. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) postulated initial core and reactor conditions, (2) methods of thermal and hydraulic analyses, (3) the sequence of events, (4) assumed reactions of reactor system components, (5) functional and operational characteristics of the reactor protection system, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations including AOOs; (2) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; (3) GDC-20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded during any condition of normal operation, including AOOs; and (4) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.1.1-4 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the excess heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the events stated.

2.8.5.2 Decrease in Heat Removal by the Secondary System

2.8.5.2.1 Loss of External Load; Turbine Trip; Loss of Condenser Vacuum; Closure of Main Steam Isolation Valve; and Steam Pressure Regulator Failure (Closed)

Regulatory Evaluation

A number of initiating events may result in unplanned decreases in heat removal by the secondary system. These events result in a sudden reduction in steam flow and, consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.1-5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the events stated.

2.8.5.2.2 Loss of Nonemergency AC Power to the Station Auxiliaries

Regulatory Evaluation

The loss of nonemergency ac power is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all reactor coolant circulation pumps. This causes a flow coastdown as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.6 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of nonemergency ac power to station auxiliaries event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the loss of nonemergency ac power to station auxiliaries event.

2.8.5.2.3 Loss of Normal Feedwater Flow

Regulatory Evaluation

A loss of normal feedwater flow could occur from pump failures, valve malfunctions, or a LOOP. Loss of feedwater flow results in an increase in reactor coolant temperature and pressure which eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a loss of normal feedwater flow. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.7 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of normal feedwater flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of the loss of normal feedwater flow. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the loss of normal feedwater flow event.

2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

Regulatory Evaluation

A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer. An increase in fuel temperature and accompanying fuel damage could then result if SAFDLs are exceeded during the transient. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the postulated initial core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) assumed reactions of reactor systems components, (5) the functional and operational characteristics of the reactor protection system, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.3.1-2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in reactor coolant flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the decrease in reactor coolant flow event.

2.8.5.3.2 Reactor Recirculation Pump Rotor Seizure and Reactor Recirculation Pump Shaft Break

Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of a reactor recirculation pump. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the postulated initial and long-term core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) the assumed reactions of reactor system components, (5) the functional and operational characteristics of the reactor protection system, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (2) GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core; and (3) GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 15.3.3-4 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the sudden decrease in core coolant flow events and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of propagating fracture of the RCPB is minimized, and adequate core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 27, 28, and 31 following implementation of the

proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the sudden decrease in core coolant flow events.

2.8.5.4 Reactivity and Power Distribution Anomalies

2.8.5.4.1 Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal from subcritical or low power startup conditions may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered (1) the description of the causes of the transient and the transient itself, (2) the initial conditions, (3) the values of reactor parameters used in the analysis, (4) the analytical methods and computer codes used, and (5) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC-25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.1 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition and concludes that the licensee's analyses have adequately accounted for the changes in core design necessary for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition.

2.8.5.4.2 Uncontrolled Control Rod Assembly Withdrawal at Power

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal at power may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered (1) the description of the causes of the AOO and the description of the event itself, (2) the initial conditions, (3) the values of reactor parameters used in the analysis, (4) the analytical methods and computer codes used, and (5) the results of the associated analyses. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC-25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal at power event and concludes that the licensee's analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal at power.

2.8.5.4.3 Startup of a Recirculation Loop at an Incorrect Temperature and Flow Controller Malfunction Causing an Increase in Core Flow Rate

Regulatory Evaluation

A startup of an inactive loop transient may result in either an increased core flow or the introduction of cooler water into the core. This event causes an increase in core reactivity due to decreased moderator temperature and core void fraction. The NRC staff's review covered (1) the sequence of events, (2) the analytical model, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC-20, insofar as it requires that the protection system be designed to initiate automatically the operation of appropriate systems to ensure that SAFDLs are not exceeded as a result of operational occurrences; (3) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during AOOs; (4) GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core; and (5) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.4.4-5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the increase in core flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, 26, and 28 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the increase in core flow event.

2.8.5.4.4 Spectrum of Rod Drop Accidents

Regulatory Evaluation

The NRC staff evaluated the consequences of a control rod drop accident in the area of reactor physics. The NRC staff's review covered the occurrences that lead to the accident, safety features designed to limit the amount of reactivity available and the rate at which reactivity can be added to the core, the analytical model used for analyses, and the results of the analyses. The NRC's acceptance criteria are based on GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core. Specific review criteria are contained in SRP Section 15.4.9 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the rod drop accident and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that appropriate reactor protection and safety systems will prevent postulated reactivity accidents that could (1) result in damage to the RCPB greater than limited local yielding, or (2) cause sufficient damage that would significantly impair the capability to cool the core. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC-28 following implementation of the EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the rod drop accident.

2.8.5.5 Inadvertent Operation of ECCS or Malfunction that Increases Reactor Coolant Inventory

Regulatory Evaluation

Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory. Depending on the temperature of the injected water and the response of the automatic control systems, a power level increase may result and, without adequate controls, could lead to fuel damage or overpressurization of the RCS. Alternatively, a power level decrease and depressurization may result. Reactor protection and safety systems are actuated to mitigate these events. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during AOOs; and (3) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.5.1-2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent operation of ECCS or malfunction that increases reactor coolant inventory and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent operation of ECCS or malfunction that increases reactor coolant inventory.

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of a Pressure Relief Valve

Regulatory Evaluation

The inadvertent opening of a pressure relief valve results in a reactor coolant inventory decrease and a decrease in RCS pressure. The pressure relief valve discharges into the suppression pool. Normally there is no reactor trip. The pressure regulator senses the RCS pressure decrease and partially closes the turbine control valves (TCVs) to stabilize the reactor at a lower pressure. The reactor power settles out at nearly the initial power level. The coolant inventory is maintained by the feedwater control system using water from the condensate storage tank via the condenser hotwell. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during AOOs; and (3) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.6.1 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent opening of a pressure relief valve event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent opening of a pressure relief valve event.

2.8.5.6.2 Emergency Core Cooling System and Loss_of_Coolant Accidents

Regulatory Evaluation

LOCAs are postulated accidents that would result in the loss of reactor coolant from piping breaks in the RCPB at a rate in excess of the capability of the normal reactor coolant makeup system to replenish it. Loss of significant quantities of reactor coolant would prevent heat removal from the reactor core, unless the water is replenished. The reactor protection and ECCS systems are provided to mitigate these accidents. The NRC staff's review covered (1) the licensee's determination of break locations and break sizes; (2) postulated initial conditions; (3) the sequence of events; (4) the analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients; (5) calculations of peak cladding temperature, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling; (6) functional and operational characteristics of the reactor protection and ECCS systems; and (7) operator actions. The NRC's acceptance criteria are based on (1) 10 CFR § 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance; (2) 10 CFR Part 50, Appendix K, insofar as it establishes required and acceptable features of evaluation models for heat removal by the ECCS after the blowdown phase of a LOCA; (3) GDC-4, insofar as it requires that SSCs important to safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer; (4) GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (5) GDC-35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel clad damage that could interfere with continued effective core cooling will be prevented. Specific review criteria are contained in SRP Sections 6.3 and 15.6.5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses of the LOCA events and the ECCS. The NRC staff concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and that the analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection system and the ECCS will continue to ensure that the peak cladding temperature, total oxidation of the cladding, total hydrogen generation, and changes in core geometry, and long-term cooling will remain within acceptable limits. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 4, 27, 35, and 10 CFR 50.46 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the LOCA.

2.8.5.7 Anticipated Transients Without Scrams

Regulatory Evaluation

ATWS is defined as an AOO followed by the failure of the reactor portion of the protection system specified in GDC-20. The regulation at 10 CFR 50.62 requires that:

- each BWR have an ARI system that is designed to perform its function in a reliable manner and be independent (from the existing reactor trip system) from sensor output to the final actuation device.
- each BWR have a standby liquid control system (SLCS) with the capability of injecting into the reactor vessel a borated water solution with reactivity control at least equivalent to the control obtained by injecting 86 gpm of a 13 weight-percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter reactor vessel. The system initiation must be automatic.
- each BWR have equipment to trip the reactor coolant recirculation pumps automatically under conditions indicative of an ATWS.

The NRC staff's review was conducted to ensure that (1) the above requirements are met, (2) sufficient margin is available in the setpoint for the SLCS pump discharge relief valve such that SLCS operability is not affected by the proposed EPU, and (3) operator actions specified in the plant's Emergency Operating Procedures are consistent with the generic emergency procedure guidelines/severe accident guidelines (EPGs/SAGs), insofar as they apply to the plant design. In addition, the NRC staff reviewed the licensee's ATWS analysis to ensure that (1) the peak vessel bottom pressure is less than the ASME Service Level C limit of 1500 psig; (2) the peak clad temperature is within the 10 CFR 50.46 limit of 2200 □F; (3) the peak suppression pool temperature is less than the design limit; and (4) the peak containment pressure is less than the containment design pressure. The NRC staff also evaluated the potential for thermal-hydraulic instability in conjunction with ATWS events using the methods and criteria approved by the NRC staff. For this analysis, the NRC staff reviewed the limiting event determination, the sequence of events, the analytical model and its applicability, the values of parameters used in the analytical model, and the results of the analyses.~~—*Insert the following sentence if the licensee relied upon generic vendor analyses* **[The NRC staff reviewed the licensee's justification of the applicability of generic vendor analyses to its plant and the operating conditions for the proposed EPU.]**~~ Review guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the information submitted by the licensee related to ATWS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on ATWS. The NRC staff concludes that the licensee has demonstrated that ARI, SLCS, and recirculation pump trip systems have been installed and that they will continue to meet the requirements of 10 CFR 50.62 and the analysis acceptance criteria following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to ATWS.

2.8.6 Fuel Storage

2.8.6.1 New Fuel Storage

Regulatory Evaluation

~~Nuclear reactor plants include facilities for the storage of new fuel. The quantity of new fuel to be stored varies from plant to plant, depending upon the specific design of the plant and the individual refueling needs. The NRC staff's review covered the ability of the storage facilities to maintain the new fuel in a subcritical array during all credible storage conditions. The review focused on the effect of changes in fuel design on the analyses for the new fuel storage facilities. The NRC's acceptance criteria are based on GDC-62, insofar as it requires the prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations. Specific review criteria are contained in SRP Section 9.1.1.~~

The HCGS EPU submittal does not request approval for a new fuel design, therefore there is no impact on the new fuel storage system.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effect of the new fuel on the analyses for the new fuel storage facilities and concludes that the new fuel storage facilities will continue to meet the requirements of GDC-62 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the new fuel storage.

2.8.6.2 Spent Fuel Storage

Regulatory Evaluation

Nuclear reactor plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the spent fuel pool and storage racks is to maintain the spent fuel assemblies in a safe and subcritical array during all credible storage conditions and to provide a safe means of loading the assemblies into shipping casks. The NRC staff's review covered the effect of the proposed EPU on the criticality analysis (e.g., reactivity of the spent fuel storage array and boraflex degradation or neutron poison efficacy). The NRC's acceptance criteria are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and (2) GDC-62, insofar as it requires that criticality in the fuel storage systems be prevented by physical systems or processes, preferably by use of geometrically safe configurations. Specific review criteria are contained in SRP Section 9.1.2.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the spent fuel storage capability and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the spent fuel rack temperature and criticality analyses. The NRC staff also concludes that the spent fuel pool design will continue to ensure an acceptably low temperature and an acceptable degree of subcriticality following implementation of the proposed EPU. Based on this, the NRC staff concludes that the spent fuel storage facilities will continue to meet the requirements of GDCs 4 and 62 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to spent fuel storage.

[2.8.7 Additional Review Areas (Reactor Systems)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 9

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

Regulatory Evaluation

The NRC staff reviewed the radioactive source term associated with EPUs to ensure the adequacy of the sources of radioactivity used by the licensee as input to calculations to verify that the radioactive waste management systems have adequate capacity for the treatment of radioactive liquid and gaseous wastes. The NRC staff's review included the parameters used to determine (1) the concentration of each radionuclide in the reactor coolant, (2) the fraction of fission product activity released to the reactor coolant, (3) concentrations of all radionuclides other than fission products in the reactor coolant, (4) leakage rates and associated fluid activity of all potentially radioactive water and steam systems, and (5) potential sources of radioactive materials in effluents that are not considered in the plant's [~~**Updated Safety Analysis Report or**~~ **Updated Final Safety Analysis Report**] related to liquid waste management systems and gaseous waste management systems. The NRC's acceptance criteria for source terms are based on (1) 10 CFR Part 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas; (2) 10 CFR Part 50, Appendix I, insofar as it establishes numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" criterion; and (3) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 11.1.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the radioactive source term associated with the proposed EPU and concludes that the proposed parameters and resultant composition and quantity of radionuclides are appropriate for the evaluation of the radioactive waste management systems. The NRC staff further concludes that the proposed radioactive source term meets the requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and GDC-60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to source terms.

NOTE: Use Sections 2.9.2 and 2.9.3 below if the licensee's radiological consequences analyses are based on an alternative source term.

2.9.2 Radiological Consequences Analyses Using Alternative Source Terms

NOTE: There are two cases that may be encountered here: (1) a licensee may be implementing an alternative source term for the first time, or (2) a licensee may have already fully implemented an alternative source term and is revising the previously approved dose analyses that use alternative source term methodologies. The second paragraph for each heading is only needed for a first-time implementation of an alternative source term (either partial or full implementations). Several accidents may have been analyzed - see corresponding SRP sections for further regulatory evaluation text (to be modified), as needed.

Regulatory Evaluation

The NRC staff reviewed the DBA radiological consequences analyses. The radiological consequences analyses reviewed are the LOCA, fuel handling accident (FHA), control rod drop accident (CRDA), and main steamline break (MSLB). The NRC staff's review for each accident analysis included (1) the sequence of events; and (2) models, assumptions, and values of parameter inputs used by the licensee for the calculation of the total effective dose equivalent (TEDE). The NRC's acceptance criteria for radiological consequences analyses using an alternative source term are based on (1) 10 CFR 50.67, insofar as it sets standards for radiological consequences of a postulated accident, and (2) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE, as defined in 10 CFR 50.2, for the duration of the accident. Specific review criteria are contained in SRP Section 15.0.1.

~~*NOTE: Use the following paragraph for a first implementation of an alternative source term:*~~

~~The NRC staff reviewed the implementation of alternative source terms. The NRC's acceptance criteria for implementation of alternative source terms are based on (1) 10 CFR 50.67, insofar as it sets standards for the implementation of an alternative source term in current operating nuclear power plants; (2) 10 CFR 50.49, insofar as it requires qualification of safety-related equipment, as defined in that section, including and based on integrated radiation dose during normal and accident conditions; (3) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE, as defined in 10 CFR 50.2, for the duration of the accident; (4) Paragraph IV.E.8 of 10 CFR Part 50, Appendix E, insofar as it requires a licensee onsite technical support center and a licensee near-site emergency operations facility from which effective direction can be given and effective control can be exercised during an emergency; and (5) plant-specific licensing commitments made in response to NUREG-0737 (Items II.B.2, II.B.3, II.F.1, III.D.1.1, III.A.1.2, and III.D.3.4). Specific review criteria are contained in SRP Sections 15.0.1.~~

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has evaluated the licensee's revised accident analyses performed in support of the proposed EPU and concludes that the licensee has adequately accounted for the effects of the proposed EPU. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of postulated DBAs since, as set forth above, the calculated total effective dose equivalent (TEDE) at the exclusion area boundary (EAB), at the low population zone (LPZ) outer boundary, and in the control room meet the exposure guideline values specified in 10 CFR 50.67 and GDC-19, as well as applicable acceptance criteria denoted in SRP Section 15.0.1. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of DBAs.

~~*NOTE: Use the following paragraph for a first implementation of an alternative source term:*~~

~~The NRC staff has reviewed the alternative source term methodology used by the licensee in evaluating the effects of the proposed EPU and concludes that changes continue to provide a sufficient margin of safety with adequate defense-in-depth to address unanticipated events and to compensate for uncertainties in accident progression, analysis assumptions, and parameter inputs. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the implementation of an alternative source term.~~

[2.9.3 Additional Review Areas (Radiological Consequences Analyses)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

NOTE: Use Sections 2.9.2 - 2.9.8 below if the licensee's radiological consequences analyses are not based on an alternative source term (i.e., if the analyses are based on a traditional source term (i.e., TID-14844)

2.9.2 Radiological Consequences of Control Rod Drop Accident

This section is not applicable because Hope Creek implemented the alternative source term.

2.9.3 Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment

This section is not applicable because Hope Creek implemented the alternative source term.

2.9.4 Radiological Consequences of Main Steamline Failure Outside Containment

This section is not applicable because Hope Creek implemented the alternative source term.

2.9.5 Radiological Consequences of a Design-Basis Loss-of-Coolant Accident

This section is not applicable because Hope Creek implemented the alternative source term.

2.9.6 Radiological Consequences of Fuel Handling Accidents

This section is not applicable because Hope Creek implemented the alternative source term.

2.9.7 Radiological Consequences of Spent Fuel Cask Drop Accidents

This section is not applicable because Hope Creek implemented the alternative source term.

HCGS utilizes a single failure proof crane and specially designed lifting devices meeting ANSI N14.6 to perform all heavy load lifts. All heavy load lifts are controlled in accordance with the requirements of NUREG 0612 and the HCGS Heavy Load Control Program. Therefore a SFP Cask Drop is not analyzed.

[2.9.8 Additional Review Areas (Source Terms and Radiological Consequences Analyses)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 10

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

Regulatory Evaluation

The NRC staff conducted its review in this area to ascertain what overall effects the proposed EPU will have on both occupational and public radiation doses and to determine that the licensee has taken the necessary steps to ensure that any dose increases will be maintained as low as is reasonably achievable. The NRC staff's review included an evaluation of any increases in radiation sources and how this may affect plant area dose rates, plant radiation zones, and plant area accessibility. The NRC staff evaluated how personnel doses needed to access plant vital areas following an accident are affected. The NRC staff considered the effects of the proposed EPU on nitrogen-16 levels in the plant and any effects this increase may have on radiation doses outside the plant and at the site boundary from skyshine. The NRC staff also considered the effects of the proposed EPU on plant effluent levels and any effect this increase may have on radiation doses at the site boundary. The NRC's acceptance criteria for occupational and public radiation doses are based on 10 CFR Part 20 and GDC-19. Specific review criteria are contained in SRP Sections 12.2, 12.3,12.4, and 12.5, and other guidance provided in Matrix 10 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on radiation source terms and plant radiation levels. The NRC staff concludes that the licensee has taken the necessary steps to ensure that any increases in radiation doses will be maintained as low as reasonably achievable. The NRC staff further concludes that the proposed EPU meets the requirements of 10 CFR Part 20 and GDC-19. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to radiation protection and ensuring that occupational radiation exposures will be maintained as low as reasonably achievable.

[2.10.2 Additional Review Areas (Health Physics)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 11

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.11 Human Performance

2.11.1 Human Factors

Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The NRC staff's human factors evaluation was conducted to ensure that operator performance is not adversely affected as a result of system changes made to implemented the proposed EPU. The NRC staff's review covered changes to operator actions, human-system interfaces, and procedures and training needed for the proposed EPU. The NRC's acceptance criteria for human factors are based on GDC-19, 10 CFR 50.120, 10 CFR Part 55, and the guidance in GL 82-33. Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0.

Technical Evaluation

The NRC staff has developed a standard set of questions for the review of the human factors area. The licensee has addressed these questions in its application. Following are the NRC staff's questions, the licensee's responses, and the NRC staff's evaluation of the responses.

1. Changes in Emergency and Abnormal Operating Procedures

   Describe how the proposed EPU will change the plant emergency and abnormal operating procedures. (SRP Section 13.5.2.1)

[Insert licensee's response followed by NRC staff statement on why the response is acceptable]

2. Changes to Operator Actions Sensitive to Power Uprate

   Describe any new operator actions needed as a result of the proposed EPU. Describe changes to any current operator actions related to emergency or abnormal operating procedures that will occur as a result of the proposed EPU. (SRP Section 18.0)

   (i.e., Identify and describe operator actions that will involve additional response time or will have reduced time available. Your response should address any operator workarounds that might affect these response times. Identify any operator actions that are being automated or being changed from automatic to manual as a result of the power uprate. Provide justification for the acceptability of these changes).

[Insert licensee's response followed by NRC staff statement on why the response is acceptable]

3. <u>Changes to Control Room Controls, Displays and Alarms</u>

Describe any changes the proposed EPU will have on the operator interfaces for control

[2.11.2 Additional Review Areas (Human Performance)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 12

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.12 Power Ascension and Testing Plan

2.12.1 Approach to EPU Power Level and Test Plan

Regulatory Evaluation

The purpose of the EPU test program is to demonstrate that SSCs will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The NRC staff's review included an evaluation of: (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance, (2) transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and (3) the test program's conformance with applicable regulations. The NRC's acceptance criteria for the proposed EPU test program are based on 10 CFR Part 50, Appendix B, Criterion XI, which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service. Specific review criteria are contained in SRP Section 14.2.1.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The staff has reviewed the EPU test program, including plans for the initial approach to the proposed maximum licensed thermal power level, transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and the test program's conformance with applicable regulations. The staff concludes that the proposed EPU test program provides adequate assurance that the plant will operate in accordance with design criteria and that SSCs affected by the proposed EPU, or modified to support the proposed EPU, will perform satisfactorily in service. Further, the staff finds that there is reasonable assurance that the EPU testing program satisfies the requirements of 10 CFR Part 50, Appendix B, Criterion XI. Therefore, the NRC staff finds the proposed EPU test program acceptable.

[2.12.2 Additional Review Areas (Power Ascension and Testing Plan)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

INSERT 13

FOR

SECTION 3.2 - BWR TEMPLATE SAFETY EVALUATION

2.13 Risk Evaluation

2.13.1 Risk Evaluation of EPU

Regulatory Evaluation

The licensee conducted a risk evaluation to (1) demonstrate that the risks associated with the proposed EPU are acceptable and (2) determine if "special circumstances" are created by the proposed EPU. As described in Appendix D of SRP Chapter 19, special circumstances are present if any issue would potentially rebut the presumption of adequate protection provided by the licensee to meet the deterministic requirements and regulations. The NRC staff's review covered the impact of the proposed EPU on core damage frequency (CDF) and large early release frequency (LERF) for the plant due to changes in the risks associated with internal events, external events, and shutdown operations. In addition, the NRC staff's review covered the quality of the risk analyses used by the licensee to support the application for the proposed EPU. This included a review of the licensee's actions to address issues or weaknesses that may have been raised in previous NRC staff reviews of the licensee's individual plant examinations (IPEs) and individual plant examinations of external events (IPEEE), or by an industry peer review. The NRC's risk acceptability guidelines are contained in RG 1.174. Specific review guidance is contained in Matrix 13 of RS-001 and its attachments.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the risk implications associated with the implementation of the proposed EPU and concludes that the licensee has adequately modeled and/or addressed the potential impacts associated with the implementation of the proposed EPU. The NRC staff further concludes that the results of the licensee's risk analysis indicate that the risks associated with the proposed EPU are acceptable and do not create the "special circumstances" described in Appendix D of SRP Chapter 19. Therefore, the NRC staff finds the risk implications of the proposed EPU acceptable.

[2.13.2 Additional Review Areas (Risk Evaluation)]

[Insert Regulatory Evaluation, Technical Evaluation, and Conclusion sections as necessary]

Attachment 13

LR-N05-0258
LCR H05-01

HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE

Marked Up Technical Specification Bases Pages
(For Information Only)

2.1 SAFETY LIMITS

BASES

2.0 INTRODUCTION

The fuel cladding, reactor pressure vessel and primary system piping are the principal barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is ≥ 1.06 for two recirculation loop operation and ≥ 1.08 for single recirculation loop operation. These MCPR values represent a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding Safety Limit is defined with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. These conditions represent a significant departure from the condition intended by design for planned operation.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

The use of the applicable NRC-approved critical power correlations are not valid for all critical power calculations performed at reduced pressures below 785 psig or core flows less than 10% of rated flow. Therefore, the fuel cladding integrity Safety Limit is established by other means. This is done by establishing a limiting condition on core THERMAL POWER with the following basis. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be greater than 4.5 psi. Analyses show that with a bundle flow of 28 x 10^3 lbs/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be greater than 28 x 10^3 lbs/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER of ~~more~~ than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 25% of RATED THERMAL POWER for reactor pressure below 785 psig is conservative.

24%

2.2 LIMITING SAFETY SYSTEM SETTINGS

BASES

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each parameter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

14%

For operation at low pressure and low flow during STARTUP, the APRM scram setting of 15% of RATED THERMAL POWER provides adequate thermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

NOTE: THIS PAGE REFLECTS CHANGES INCLUDED IN PSEG LETTER LR-N04-0062, dated 06/07/04

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The ~~15%~~ 14% neutron flux trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Fixed Neutron Flux-Upscale setpoint; i.e, for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Flow Biased Simulated Thermal Power-Upscale setpoint, a time constant of 6 ± 0.6 seconds is introduced into the flow biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow biased setpoint as shown in Table 2.2.1-1.

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unnecessary shutdown. ~~The flow referenced trip setpoint must be adjusted by the specified formula in Specification 3.2.2 in order to maintain these margins when CMFLPD is greater than or equal to FRTP.~~

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine control valve fast closure and turbine stop valve closure trip are bypassed. For a load rejection or turbine trip under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

REACTIVITY CONTROL SYSTEMS

BASES

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 10% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RWM to be OPERABLE when THERMAL POWER is less ~~than or~~ equal to 10% of RATED THERMAL POWER provides adequate control. 8.6%

The RWM provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4.9 of the FSAR and the techniques of the analysis are presented in Reference 1.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density during high power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal soon enough to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods. Operability of a RBM channel is assured for a given control rod when ≥ 50% of the LPRM inputs for each detector level are available for that rod. When < 50% of the LPRM inputs on either detector level are available, a case-by-case evaluation of channel operability is required.

Note: This page reflects changes included in PSEG letter LR-N05-0032, dated 02/18/05.

~~APRM SETPOINTS (Continued)~~

~~and the flow biased neutron flux-upscale control rod block trip setpoints must be adjusted to ensure that the MCPR does not become less than the fuel cladding Safety Limit or that > 1% plastic strain does not occur in the degraded situation. The scram setpoints and rod block setpoints are adjusted in accordance with the formula in Specification 3.2.2 whenever it is known that the existing power distribution would cause the design LHGR to be exceeded at RATED THERMAL POWER.~~

3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady state operating limit, it is required that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest delta MCPR. When added to the Safety Limit MCPR, the required ~~minimum operating limit MCPR of Specification 3.2.3 is obtained.~~

~~The MCPR operating limits derived from the transient analysis are~~ dependent on the operating core flow ~~(K_f)~~ and power state (MCPR(f) and MCPR(p), respectively) to ensure adherence to fuel design limits during the worst transient with ~~moderate~~ frequency that is postulated in Chapter 15.

Flow dependent MCPR limits ~~(K_f)~~ (MCPR(f)) ~~are determined~~ by steady state methods using a core thermal hydraulic code (Reference 1). ~~K_f~~ curves are provided based on the maximum credible flow runout transient (i.e., runout of both loops).

INSERT 1

~~At THERMAL POWER levels less than or equal to 25% of RATED THERMAL POWER, the reactor will be operating at minimum recirculation pump speed and the moderator void content will be very small. For all designated control rod patterns which may be employed at this point, operating plant experience indicates that the resulting MCPR value is in excess of requirements by a considerable margin. During initial start-up testing of the plant, a MCPR evaluation will be made at 25% of RATED THERMAL POWER level with minimum recirculation pump speed. The MCPR margin will thus be demonstrated such that future MCPR evaluation below this power level will be shown to be unnecessary. The daily requirement for calculating MCPR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR when a limiting~~

NOTE: THIS PAGE REFLECTS CHANGES INCLUDED IN PSEG letter LR-N05-0032, dated 02/18/05

MINIMUM CRITICAL POWER RATIO (Continued)

~~control rod pattern is approached ensures that MCPR will be known following a change in THERMAL POWER or power shape, regardless of magnitude, that could place operation at a thermal limit.~~

3/4.2.4 LINEAR HEAT GENERATION RATE

The LHGR is a measure of the heat generation rate of a fuel rod in a fuel assembly at any axial location. This specification assures that the Linear Heat Generation Rate (LHGR) in any fuel rod is less than the design linear heat generation even if fuel pellet densification is postulated. Limits on LHGR are specified to ensure that fuel design limits are not exceeded anywhere in the core during normal operation, including anticipated operational occurrences (AOOs), and to ensure that the peak clad temperature (PCT) during postulated design basis loss of coolant accident (LOCA) does not exceed the limits specified in 10 CFR 50.46. Exceeding the LHGR limit could potentially result in fuel damage and subsequent release of radioactive materials. Fuel design limits are specified to ensure that fuel system damage, fuel rod failure, or inability to cool the fuel does not occur during normal operation or the anticipated operational occurrences identified in Reference 1.

The analytical methods and assumptions used in evaluating the fuel system design limits are presented in Reference 1. The analytical methods and assumptions used in evaluating AOOs and normal operation that determine the LHGR limits are presented in Reference 1.

LHGR limits are developed as a function of exposure to ensure adherence to fuel design limits during the limiting AOOs. The exposure dependent LHGR limits are reduced by an LHGR multiplier (LHGRFAC) at various operating conditions to ensure that all fuel design criteria are met for normal operation and AOOs. A complete discussion of the analysis code is provided in Reference 2. INSERT 2

For single recirculation loop operation, the LHGRFAC multiplier is limited to a maximum value as given in the CORE OPERATING LIMITS REPORT. This maximum limit is due to the conservative analysis assumption of an earlier departure from nucleate boiling with one recirculation loop available, resulting in a more severe cladding heatup during a LOCA.

References:

1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," (latest approved version).

2. NEDO-24154-A, "Qualification of the One-Dimensional Core Transient Model (ODYN) for Boiling Water Reactors," August 1986, and NEDE-24154-~~P-A, Supplement 1, Volume 4, Revision 1, February 2000.~~

3. NEDC-33153P, "SAFER/GESTR-LOCA Loss of Coolant Accident Analysis for Hope Creek Generating Station," Revision 1, September 2004

INSERT 1

The methods described in Reference 1 are used to determine the power dependent MCPR limits (MCPR(p)). Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scram limits are bypassed, high and low MCPR(p) operating limits are provided for operation between ~~25%~~ 24% of RATED THERMAL POWER and the bypass power levels.

INSERT 2

Flow-dependent LHGR limits were developed to assure adherence to all fuel thermal-mechanical design bases for the slow recirculation flow runout event. From the bounding overpowers, the limits were derived such that, during these events, the peak power would not exceed fuel thermal-mechanical limits. The flow-dependent LHGR limits are generic and cycle-independent, and are specified in terms of a multiplier, LHGRFAC(f), to be applied to the rated LHGR values.

Power-dependent LHGR limits, are substituted to assure adherence to the fuel thermal-mechanical design bases at reduced power conditions. Both incipient centerline melting of the fuel and plastic strain of the cladding are considered in determining the power-dependent LHGR limit although the limiting criterion is generally incipient centerline melting. Appropriate LHGR limits are selected based on generic and plant specific transient analyses. These limits are derived to assure that the peak transient power for any transient is not increased above the fuel design basis values. The power-dependent LHGR limits are specified in terms of a multiplier, LHGRFAC(p), to be applied to the rated LHGR values.

Although the LOCA analyses do not credit any reductions in LHGR or MAPLHGR during two-loop operation, the application of the ARTS based fuel thermal-mechanical design analysis limits (LHGRFAC(p) and LHGRFAC(f)) are required to ensure that off-rated conditions not specifically analyzed will not be limiting. (Reference 3)

NOTE: THIS PAGE REFLECTS CHANGES INCLUDED IN PSEG letter LR-N05-0032, dated 02/18/05

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is an essential safety supplement to the reactor trip. The purpose of the EOC-RPT is to recover the loss of thermal margin which occurs at the end-of-cycle. The physical phenomenon involved is that the void reactivity feedback due to a pressurization transient can add positive reactivity to the reactor system at a faster rate than the control rods add negative scram reactivity. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than ~~30%~~ of RATED THERMAL POWER are annunciated in the control room.
24%

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 175 ms. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression (135 ms @ 100% RTP), and the response time of the system logic.

Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.11 Oscillation Power Range Monitor (OPRM)

APPLICABLE SAFETY ANALYSES (continued)

control, and protection systems to be designed with appropriate margin to assure that acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. GDC 12 requires assurance that power oscillations which can result in conditions exceeding acceptable fuel design limits are either not possible or can be reliably and readily detected and suppressed. The OPRM System provides compliance with GDC 10 and GDC 12 by detecting the onset of oscillations and suppressing them by initiating a reactor scram. This assures that the MCPR safety limit will not be violated for anticipated oscillations.

The OPRM Instrumentation satisfies Criteria 3 of the Final Commission Policy Statement on Technical Specifications Improvements for Nuclear Power Reactors, dated July 22, 1993 (58 FR 39132).

LCO

Four channels of the OPRM System are required to be OPERABLE to ensure that stability related oscillations are detected and suppressed prior to exceeding the MCPR safety limit. Only one of the two OPRM modules' period based detection algorithms is required for OPRM channel OPERABILITY. The highly redundant and low minimum number of required LPRMs in the OPRM cell design ensures that large numbers of cells will remain operable, even with large numbers of LPRMs bypassed.

APPLICABILITY

Consistent with the basis

The OPRM instrumentation is required to be OPERABLE in order to detect and suppress neutron flux oscillations in the event of thermal-hydraulic instability. As described in References 1, 2, and 3, the region of anticipated oscillation is defined by THERMAL POWER ≥ 30% RTP and recirculation drive flow ≤ the value corresponding to 60% of rated core flow. Therefore, the OPRM trip is required to be enabled in this region. However, to protect against anticipated transients, the OPRM is required to be OPERABLE with THERMAL POWER ≥ 25% RTP. This provides sufficient margin to potential instabilities as a result of a loss of feedwater heater transient. It is not necessary for the OPRM to be OPERABLE with THERMAL POWER < 25% RTP because instabilities are not anticipated to result from any expected transients below this power.

26.1%

24%

ACTIONS

a.1, a.2 and a.3

Because of the reliability and on-line self-testing of the OPRM instrumentation and the redundancy of the RPS design, an allowable out of service time of 30 days has been shown to be acceptable (Ref. 7) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the OPRM instrumentation still maintains OPRM trip capability (refer to Required Action b.1). The remaining OPERABLE OPRM channels continue to provide trip capability and provide operator information relative to stability activity. The remaining OPRM modules have high reliability. With this high reliability, there is a low probability of a subsequent channel failure within the allowable out of

3/4.3.11 Oscillation Power Range Monitor (OPRM)

ACTIONS (continued)

service time. In addition, the OPRM modules continue to perform on-line self-testing and alert the operator if any further system degradation occurs.

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the OPRM channel or associated RPS trip system must be placed in the tripped condition per required actions a.1 and a.2. Placing the inoperable OPRM channel in trip (or the associated RPS trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the OPRM channel (or RPS trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), the alternate method of detecting and suppressing thermal-hydraulic instability oscillations is required (Required Action a.3). This alternate method is described in Reference 5. It consists of increased operator awareness and monitoring for neutron flux oscillations when operating in the region where oscillations are possible. If indications of oscillation, as described in Reference 5, are observed by the operator, the operator will take the actions described by procedures, which include initiating a manual scram of the reactor.

b.1 and b.2

Required action b.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped OPRM channels within the same RPS trip system result in not maintaining OPRM trip capability. OPRM trip capability is considered to be maintained when sufficient OPRM channels are OPERABLE or in trip (or the associated RPS trip system is in trip), such that a valid OPRM signal will generate a trip signal in both RPS trip systems. This would require both RPS trip systems to have one OPRM channel OPERABLE or in trip (or the associated RPS trip system in trip).

Because of the low probability of the occurrence of an instability, 12 hours is an acceptable time to initiate the alternate method of detecting and suppressing thermal-hydraulic instability oscillations described in Reference 5. The alternate method of detecting and suppressing thermal-hydraulic instability oscillations would adequately address detection and mitigation in the event of instability oscillations. Based on industry operating experience with actual instability oscillation, the operator would be able to recognize instabilities during this time and take action to suppress them through a manual scram. In addition, the OPRM System may still be available to provide alarms to the operator if the onset of oscillations were to occur. Since plant operation is minimized in areas where oscillations may occur, operation for 120 days without OPRM trip capability is considered acceptable with implementation of the alternate method of detecting and suppressing thermal-hydraulic instability oscillations.

c 24% 24%

With any required ACTION not met within the specified time interval, THERMAL POWER must be reduced to < ~~25%~~ RTP within 4 hours. Reducing THERMAL POWER to < ~~25%~~ RTP places the plant in a region where instabilities cannot occur. The 4 hours is reasonable, based on operating experience, to reduce THERMAL POWER < ~~25%~~ RTP ~~from~~ full power conditions in an orderly manner and without challenging plant systems.

3/4.3.11 Oscillation Power Range Monitor (OPRM)

SURVEILLANCE REQUIREMENTS (continued)

26.1%

SR 4.3.11.5

This SR ensures that trips initiated from the OPRM system are not inadvertently bypassed when the capability of the OPRM system to initiate an RPS trip is required. The trip capability of the OPRM system is only required during operation under conditions susceptible to anticipated T-H instability oscillations. The region of anticipated oscillation is defined by THERMAL POWER ≥ ~~30%~~ RTP and recirculation drive flow ≤ the value corresponding to 60% of rated core flow.

The trip capability of individual OPRM modules is automatically enabled based on the APRM power and flow signals associated with each OPRM channel during normal operation. These channel specific values of APRM power and recirculation drive flow are subject to surveillance requirements associated with other RPS functions such as APRM flux and flow biased simulated thermal power with respect to the accuracy of the signal to the process variable. The OPRM is a digital system with calibration and manually initiated tests to verify digital input including input to the auto-enable calculations. Periodic calibration confirms that the auto-enable function occurs at appropriate values of APRM power and recirculation flow signal. Therefore, verification that OPRM modules are enabled at any time that THERMAL POWER ≥ 26.1% ~~30%~~ RTP and recirculation drive flow ≤ the value corresponding to 60% of rated core flow adequately ensures that trips initiated from the OPRM system are not inadvertently bypassed.

The trip capability of individual OPRM modules can also be enabled by placing the module in the non-bypass (Manual Enable) mode. If placed in the non-bypass or Manual Enable mode the trip capability of the module is enabled and this SR is met. The frequency of 18 months is based on engineering judgment and reliability of the components.

SR 4.3.11.6

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis (Ref. 8). The OPRM self-test function may be utilized to perform this testing for those components it is designed to monitor. The RPS RESPONSE TIME acceptance criteria are included in Reference 8.

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time. RPS RESPONSE TIME tests are conducted such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip system. This Frequency is based upon operating experience, which shows that random failures of instrumentation components causing serious time degradation, but not channel failure, are infrequent.

**HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354**

**REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
1999 PRA PEER REVIEW**

This Attachment summarizes the A&B Facts and Observations (F&Os) from the PRA peer review of the Hope Creek 1999 PRA Model.

These Facts and Observations (F&O) were resolved and inserted into both the model and PRA documentation as part of the 2003A PRA model update. This model (2003A) was subsequently adopted by PSEG as Revision 2.0 with additional improvements. Revision 2.0 then was further updated to include additional changes that resulted in the current 2005B model which also includes all of the F&O resolutions from the 1999 PRA Peer Review.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
AS	7	ATWS Modify the RPS failure probabilities consistent with the Utility Group on ATWS or the NUREG/CR-5500, Vol. 3 information. The scram failure probability and the credit assigned to ARI must be consistent. This does not appear to be the case in the current model.	B	The concern is that there were inconsistencies in the ATWS model regarding the effectiveness of the ARI. In some cases, such as mechanical failures of the scram systems, the ARI may not be effective. New ATWS event trees have been developed. Two categories of ATWS are modeled: RPS-Electrical (RPSE) and RPS-Mechanical (RPSM). For RPSM, the ARI is not going to be effective and for RPSE, the ARI is going to be effective. The NUREG/CR-5500 information is used to derive the new model. Based on discussions carried out with the principal author of the NUREG/CR-5500, frequencies have been assigned to RPSE and RPSM. It is judged that the RPSM model subsumes the RPSE model. The RPSE has lower frequency and the ARI can be effective. It should be noted that the same issue has been raised in a number of places.
AS	11	ATWS C(4) Node – Late Boron Injection The C(4) node is assigned a 0.1 failure probability. However, this point estimate does not appear to be linked to the types of previous failures that have occurred. If SLC has failed because of hardware failures, then the C(4) node is considered not to be feasible to obtain repair or recovery of the SLC system. In addition, the time frame for the action is considered to be substantially longer than the 20 min. usually assessed. The technical basis for the time frame is not included in the documentation.	B	Completed for 2003 PSA Update. Removed from PRA success conditions and no longer credited based on input received during the HRA interviews.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
AS	11	Based on a presentation given by the PRA Group, credit for ARI is incorporated into both the Electrical and Mechanical ATWS initiating event frequencies.	B	See P. AS-02 (AS-7).
AS	14	<u>Accident Sequence Formulation</u> CRD appears not to be credited for high RPV pressure injection at t = 0. However, the fault tree model includes it. This relies on the specific BED file to eliminate it. Accident Classes are not defined in the documentation for Level 1 - only included in Level 2 write-up. PCS Recovery for non-ATWS is not in EOPs (1993 or 1999) need justification for credit of this manual action. LP permissive appears to be truncated out of sequences. VR node is likely not adequate for transient (no calculation available to justify) Manual depressurization values are not supported RPV depressurization values vary substantially from ET to ET. This seems incorrect. The values are all too high. Core damage with no heat removal There is not a clear link to the cause of core damage given failure of containment heat removal.	B	Completed for 2003 PSA Update. See Event Tree Notebook

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
AS	17	Vapor Suppression The vapor suppression system does not appear to be addressed as a required mitigation system for LOCAs and IORV even though the event tree discussion includes vapor suppression as a required function. Low Pressure Injection The use of Fire pump or the condensate transfer pumps would appear to require extensive calculations to support their use as successful low pressure injection systems. These do not appear to be available. The SW x-tie to RPV injection is not included.	B	Vapor Suppression Completed as specified for 2003 PSA Update. Alt. Injection DFP used for injection based on MAAP for HCGS

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
AS	17	The following items appear to be missing from the success criteria table, Table 3.1.1-4. ATWS: RPT RPV overpressure protection is not addressed with RPT. RPT is generally required to suppress the pressure peak following ATWS events. RCIC RCIC as a high pressure makeup source under ATWS1 conditions may be successful under certain limited circumstances however a technical basis and the limitations on its applicability need to be defined. Non ATWS Overpressure Protection HPCI in full flow test. Main Steam Line Drain Open: This option for RCS overpressure protection is quite unusual to credit in the PRA. It would require identification of the timing and operator actions to define the constraints, plus include the supports or other systems necessary to make this a success path. It would appear that this is not able at all for LOOP and loss of condenser vacuum.	B	Completed for 2003 PSA Update The failure of RPT directly leads to CD. The 2nd concern is the capacity of RCIC under certain ATWS conditions. The RCIC has been removed from the ATWS tree as a success. The 3rd concern is using other means of overpressure protection. Though the option is listed, they have not been credited.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
AS (CONT'D)	17	Success Criteria VR Node in Event Tree The alignment of the RHR system as injecting through the Hx to the RPV is credited for containment heat removal. However, since the flow may be 100 gpm or less, it is not clear that the heat removal capability is sufficient at these low flow rates.		No credit for RHR heat removal via the Hx if aligned for injection in a non-LOCA.
AS	17	Success Criteria SACS P. 3.2-161 and 3.2-164 say 1 SACS pump in each loop can support safe shutdown. This does not appear to be the fault tree success criteria used. Missing Ref. 7 for SSWS and SACS.	B	The concern is about the modeling of SAC system. The SAC system has been extensively remodeled to match with the current success criteria. This is documented in an answer to Subelement TH-9.
AS	17	ATWS – Success Criteria The write-up indicates that RCIC is not adequate to provide RPV level control for ATWS (p. 3.1-16). This is consistent with the generic analysis that has been performed to support the PSAs. However, the ATWS model implementation credits HPCI and RCIC for the purposes of ATWS RPV level control. This is non-conservative.	B	The concern is about the credit for RCIC under ATWS conditions. As discussed previously, RCIC is removed from the ATWS model as an injection success.
AS	18	The event trees credit re-opening the MSIVs and recovery of the PCS for non-ATWS sequences. However, the Rev. 4 EPG based HCGS EOPs used in Rev. 1 of the HCGS PSA only direct re-opening the MSIVs for ATWS scenarios and do not direct such actions for non-ATWS scenarios.	B	Completed for 2003 PSA Update. See 2003 Event Tree and HRA Notebooks to clarify the treatment of MSIV reopening for non-ATWS conditions.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
AS	18	ATWS There is substantial concern regarding the position taken in the ATWS sequence evaluation that the use of LP injection is not credited. The implication from the discussion is that there is substantial difficulty in the use of LP systems and therefore if high pressure system cannot be used, then core damage will result. If this is the case, there could be a serious problem because late SLC should always result in depressurization or HCTL. This is not accounted for.	B	Completed for 2003 PSA Update. LP injection success is properly accounted for in 2003A model.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
AS	18	The EOP modification to go from EPG Rev. 4 Based Procedure to EPG/SAG based procedures involved some substantial changes to the plant proceduralized response. The EOPs used in the evaluation are the EPG Rev. 4 Based EOPs. These have been superseded on approximately 1/1/99. The use of the latest EOPs would be desirable in the model. This may require an HRA reassessment <u>or</u> it can be performed only on those significant areas affected: • RPV injection above MPCWLL • Inhibit ADS in ATWS • Level 2 • MSIV reopening perception (EOP 101) <u>Note on Level 1 Analysis</u> The change to the RPV injection at MPCWLL will make Class 2C less important (possibly negligible) and increase the need to accurately address RPV injection after containment breach. There is no requirement to terminate RPV injection despite core damage. This results in the potential for sequences with all heat removal systems failed to still result in a success.	B	Completed for 2003 PSA update. ATWS model completely revamped to address each issue
DA	4	The Bayesian updates for the HPCI and RCIC fail-to-start basic event appear to be non-conservative. (see DA-9)	B	Completed for 2003 PSA update. See Component Data Notebook for the use of plant specific data for the Bayesian update.
DA	5	Similar types of components (e.g., RCIC & HPCI MOVs) are not grouped together	B	Completed for 2003 PSA update. See Component Data Notebook.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
DA	9	The HPCI/RCIC common cause parameters used are based directly on NUREG/CR-5497, but the values used differ from those in the NUREG. The fail-to-start α_2 used in Table E-2 was 3.79E-3, while the NUREG gives 1.39E-3 (the same as the β value). The fail-to-run α_2 used in Table E-2 was 2.81E-3, while the NUREG gives 1.51E-4 (the same as the β value). (see DA-4)	B	Modified to be consistent with NRC recommended values.
DA	10	Only one inter system grouping for common cause groups (HPCI & RCIC TDP FTR FTS). Should consider low pressure suction strainers across system groupings (LPCI & CS), low pressure injection valves, HPCI & RCIC CST suction valves	B	Completed for 2003 PSA update. See Component Data Notebook. a) The inter system CCF grouping of LPCI and CS suction strainers is incorporated into the HCGS PSA 2003. According to NUREG/CR-5497 the potential for this failure mode exists. b) The inter system CCF grouping of LPCI and CS valves are not considered due to the differences in system's flow rates, line sizes, locations, duty cycle, and system design (References HCGS PSA Revision 1.0, Drawings M-51-1 and M-52-1). The HPCI and RCIC CST suction valves are not modeled based on assumptions 9, 11 on page 3.2-11 and assumptions 5,9 on page 3.2-19 of the HCGS PSA Revision 1.0. The non-modeling of these valves was confirmed by examining the HCGS PSA model. Therefore, the CCF modeling of the HPCI and RCIC CST suction valves is not needed. The inter system CCF grouping of other HPCI and RCIC valves are not considered due to the differences in system's flow rates, line sizes, and locations (References HCGS PSA Revision 1.0, Drawings M-49-1, M-50-1, M-55-1, and M-56-1).

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
DA	11	No discussion/disposition of CCF for onsite AC source design features e.g., design/diversity issues between the diesel generators and the gas jet (Salem 3). Common maintenance crews/ bad fuel oil, etc...	B	The HCGS PSA Revision 1.0 used the Salem Gas Turbine Generator, basic event "NR-DG-DF-6," as a recovery for onsite. The HCGS PSA Revision 1.1 replaced this recovery basic event with a developed subtree. No Common Cause Failure is expected between the failure of the HCGS diesel generators and the failure of power from the Salem units since Hope Creek and Salem have different maintenance crews, procedures, and operations.
DA	12	NUREG/CR-5497 appears to give common cause factors across system boundaries for ECCS suction strainer plugging. The values used for Core Spray and RHR in Table E-2 differ from the values in NUREG/CR-5497 and are not used across system boundaries.	B	Completed for 2003 PSA update as requested. See Component Data Notebook
DA	15	The sources of unique unavailabilities are not well documented. They are listed in Table D-4. The basis for recovery of the DG (NR-DG-DF-6) is a point value (.5) based on a memorandum that could not be located. NR-LOSP-5 is obtained from NUREG 5496 Table 3-8. No plant specific data was used.	B	Completed for 2003 PSA update. This was set to 1.0 failure. See Appendix G of Component Data Notebook.
DA	15	No basis is provided for the diesel generator mission time of 12 hours.	B	Completed for 2003 PSA update. D/G mission time developed based on convolution assessment. See Appendix G of Component Data Notebook.
DA	16	RPS is not correctly characterized	B	Completed for 2003 PSA update. (See AS-7)
DE	3 and 13	The HRA for the entire set of post-initiators is not documented. Section 3 of the PSA does not provide calculation summaries and does not list values for the "non-NR" HEPs, and Appendix H documentation only addresses the NR HEPs. Also refer to Fact/Observation HR-30.	B	Completed for 2003 PSA update. HRA completely revamped. Documentation added for all HEPs (123 HEPs).

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
DE	6	Dependence of human action failure probability for actions in the same accident sequence could lead to significant increase in the human error contribution to risk. To ensure that such dependencies have not been underestimated and truncated during quantification, PSE&G quantified the risk by increasing all HEP values less than 0.1 to the value of 0.1. The results of this case have not been analyzed or reported in the Rev 1 PSA report. Evaluating the results of this quantification and their impact on the assumed HEP values and risk should be included in the Rev. 1 report.	B	Completed for 2003 PSA update See also HR-29, -31, and –32. Dependent HEPs are assessed and quantified in the 2003 model. The results are documented in the 2003 HRA notebook.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
HR	6	The pre-initiator human error probabilities are based on THERP calculations, which is an acceptable practice. These HEPs are then adjusted, prior to incorporation in the PSA, by the equation UA= HEP (FDT/INT), where • UA is the component unavailability due to the pre-initiator error • FDT is the "fault duration time before detection" • INT is the "interval between calibrations" This adjustment approach is not familiar to the Cert Team analysts and could not be located from a quick review of The Handbook. No supporting information was available for review. While the adjustment to the HEP is understandable (i.e., analogous to a standby failure analysis to determine the likelihood that the miscalibration condition exists at the time of function demand) and generally acceptable to the Cert Team, no bases are provided for FDT and INT parameters - the FDT parameter being the one of more concern (it is very unclear as to how such a parameter would be determined).	B	Pre initiator formalism abandoned for 2003 PRA update in favor of EPRI HRA calculator. All pre-initiators re-evaluated.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
HR	6	The pre-initiator "unavailabilities" calculated by the equation UA= HEP (FDT/INT) and summarized in Table 3.3.3-6 are not necessarily those used in the fault trees. After calculation of HEPs using THERP, then adjusting the HEPs with FDT/INT, these values are then generally input into basic events as failure rates with mission times. Some of these mission times are as low as <5 minutes, creating some very low pre-initiator failure probabilities in the model (e.g., 9E-7). This process is very suspect, and appears to be incorrect.	B	Pre initiator formalism abandoned for 2003 PRA update in favor of EPRI HRA calculator. All pre-initiators re-evaluated.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
HR	7	The CS injection valves have a low pressure interlock that must function to allow CS to operate. The logic is of 1-of-2-taken-twice. The transmitters are 90B, 90F, 90K, 90P. The following appears lacking: • The miscalibration HEP of these sensors appears to be too low at 1.65E-6 and no adequate basis is presented. • The system notebook does not discuss this logic or the failure modes, or the quantification of the failure modes. • The RAW and FV of the FV of the miscalibration of all low pressure interlock transmitters (LPCI and CS) do not appear consistent with the impact these have on the fault trees – see attached. • The truncation of 1E-10/yr leads to truncating many sequences with this failure included, e.g., Large LOCA.	B	Completed for 2003 PSA update. All items resolved for 2003 model.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
HR	9	There is no calculation to demonstrate that SRV accumulators are adequate for a 24 hour mission time. This implies that the external pneumatic source is needed to provide SRV control. Include opening external pneumatic supply to containment in Depressurization evaluation.	B	Completed for 2003 PSA update
HR	10	Manual Vent HEP Could not locate technical basis for this manual action.	B	Completed for 2003 PSA update
HR	10	ADS Inhibit The ADS inhibit failure probability was modified from 7.5E-2 (pre – 7/19/97) to 1E-4, and no associated documentation was presented to the Certification Team. The ADS inhibit failure probability is judged, based on other BWR PSAs, to be in the 1E-2 range. A value of 1E-4 for an action with very strong time constraints would appear unreasonable, particularly using the ORE methodology.	B	Completed for 2003 PSA update
HR	12	Various screening values and later HRA evaluations have been included in the model without technical basis. The screening values are not always believed to be applied in a "conservative" manner, i.e., the SACS cross tie for support of diesel generator cooling may not be conservative. The latest HRA (e.g., ADS inhibit) is developed without a detailed technical basis and is likely inconsistent with the previous methodology. No discussion of performance shaping factors identified.	B	HRA completely revamped. Documentation added for all HEPs (123 HEPs).

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
HR	12	Depressurization The failure probability to depressurize of 1E-3 appears to be consistent with a time of 30 min. The time available is believed longer based on the recent MAAP cases, i.e., 60 min. The associated probability should be lower than the value cited in the documentation of 1E-3. ADS inhibit for ATWS sequences in the latest model is less than RPV depressurization (i.e., 1E-4 versus 1 to 8E-3)	B	Completed for 2003 PSA update. The HCGS EPU configuration has been reevaluated using MAAP 4 and the results are input into a revised HRA calculation.
HR	15	SACS – D/G Cooling The use of SACS Train B to supply cooling to Diesel Generators A & C is not considered to be evaluated with HRA performance shaping factors representative of the time constraints and available procedural guidance. The HEP is the same as that used for the cross-tie of SACS for long term cooling restoration. SDA-XHE-FO-SACB	B	No longer in model for 2003.
HR	15	SACS Room cooling for accident scenarios with loss of the aligned SACS system have included a backup to use the alternate SACS train. This alignment appears to be ill-defined. The HRA for the alignment is not well characterized. RHS-XHE-FO-ALIGN	B	See HR-15.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
HR	15	<u>Post Initiator Screening</u> The use of 0.1 as a screening HEP is not considered conservative for cases in which the action is not proceduralized or bypassing of interlocks is required, or time constraints limit response. Examples include: • Bypass low level MSIV closure interlock • Use opposite Div. SACS cooling to D/G under LOSP • Cross tie SW under LOSP for D/G cooling	B	Completed for 2003 PSA update. HRA completely reassessed all issues addressed. Crew interviews, procedures checked, performance shape factors included.
HR	16	The EOPs used in the evaluation are the EPG - Rev. 4 based EOPs. These have been superseded on approximately 1/1/99. The use of the latest EOPs would be desirable in the model. This may require an HRA re-assessment <u>or</u> it can be performed only on those significant areas affected: • Inhibit ADS in ATWS • RPV injection above WLL • Level 2 • MSIV reopening perception (EOP 101) <u>Note on Level 1 Analysis</u> The change to the RPV injection at MPCWLL will make Class 2C less important (possibly negligible) and increase the need to address RPV injection after containment breach.	B	Completed for 2003 PSA update. Latest procedures used in HRA update (2003).

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
HR	18	HRA Containment Vent Local Action The plant has a special and unique set of capabilities to vent containment. The capabilities include: • 2 hard pipe vent paths • capability on the torus vent path to vent - with bottled gas, i.e., compressors not required - manually with no DC or no pneumatics There does not appear to have been an HRA performed to support this evaluation. The performance shaping factors affecting this are: • extreme conditions in the containment (prohibitive if) • time limitation not addressed -- several hundred manual strokes required ambiguity regarding whether the action is to be taken if DW pressure is > 35 psig	B	Completed as part of the 2003 PRA HRA update. A revised HEP evaluation is performed for each of the vent paths in the model and including dependencies on previous success or failure of torus cooling crew actions.
HR	23	The event trees credit operator actions for re-opening the MSIVs and recovery of the PCS for non-ATWS sequences. However, the Rev. 4 EPG based HCGS EOPs used in Rev. 1 of the HCGS PSA only direct re-opening the MSIVs for ATWS scenarios and do not direct such actions for non-ATWS scenarios.	B	Completed for 2003 PSA update See AS-18.
HR	26, 27	There are a substantial number of multiple HEPs that occur in model cutsets if the truncation level is lowered sufficiently or if these HEPs are increased in probability.	B	(Same comment placed under HR, QU and DE elements) Completed for 2003 PSA update.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFICANCE	PLANT RESPONSE OR RESOLUTION
		These multiple HEPs in the same cutset need to be address to determine whether there are dependencies among them that are to be addressed. Guidance/documentation exists that says there is a process to address multiple HEPs. This guidance was not generally followed. A separate study of the multiple HEPs in cutsets was performed, but was performed above the truncation limit. This is judged not adequate. A cutset reassessment has been performed by PSE&G with HEPs set to 0.1 or greater during the certification. The results are that there are multiple recoveries within the same cutset. The compatibility or independence of these events such that they can be included in the same cut set is not documented. This compatibility should be established in the documentation (see attached). The cutsets printed out for the case with HEPs set to 0.1 (refer to QU #10/17), or their original value if higher indicates a large number of combinations with the potential for dependence. Examples include the following: • Two ventilation actions on both A & C ventilation • Two non-recovery actions associated with depressurization and ECCS • Two non-recovery actions both associated with decay heat removal alignments • Four separate HEPs all in the same cutset		Dependencies are re-evaluated with the latest model and the updated HRA. Each of the specific items is addressed.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
HR	27	<u>Dependent Actions Treatment</u> At the Certification, a brief "White Paper" was presented to describe potentially dependent HEPs appearing in cutsets. This is considered a strong positive indication of the pursuit of model fidelity and level of detail. Certain enhancements to this process are considered desirable. For dependence analysis: • The HEP combinations should be addressed in terms of: - timing - symptoms - cues - complexity - crew involvement (which team members) • The HEP combinations should be identified by a separate quantification with HEPs set to 0.1 or higher.	B	Completed for 2003 PSA update. Refer also to DE-6.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
HR	30	The current HRA is documented in a fragmented manner that creates a difficult task to maintain it current with the model, e.g., HRA descriptions are contained in the following: 1. SAI Report on certain non-recovery probabilities 2. Section 3 of IPE 3. Appendix H of IPE 4. RAI responses 5. Other missing information such as the post initiator HEPs that could not be retrieved for the Certification Team In addition, the HRA analysis for the entire set of post-initiator HEPs is not documented. Section 3 of the PSA does not provide calculational summaries and does not list the values of "non NR" HEPs, and the Appendix H documentation is only for the NR HEPs.	B	Completed for 2003 PSA update. HRA completely revamped. Documentation added for all HEPs (123 HEPs).
HR	30	The Appendix H documentation does not appear to match what is actually currently used in the model (e.g., emergency depressurization calc. does not match HEP value in model).	B	Completed for 2003 PSA update. HRA completely revamped. Documentation added for all HEPs (123 HEPs).

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
IE	7	Modeling of Steam-Line Break Outside Containment is useful when analyzing high-energy line break issues and may influence the LERF determination. The following BOC events are not addressed: • HPCI • RCIC • Main Steam lines • RWCU The BOC IE cannot be excluded without further investigation because it impacts both CDF and LERF	B	Resolution completed and added to documentation and model. BOC initiating events developed and analyzed as part of the PSA to ensure LERF is appropriately calculated.
IE	7	Some initiators that may be not addressed include the following: • Loss of Multiple DC Buses • Loss of non-Safety AC buses	B	For the 2003 PSA Update: Loss of single DC bus not an initiator. The DC system bus loading has been reviewed to see if loss of any one division of DC power would cause a scram. A systematic search of the loads on each bus has identified no possibility in which one division loss of DC would induce a possible scram at Hope Creek. Multiple DC bus failure is included as an IE. Non-safety AC buses are included as I.E. if they cause a scram.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
IE	9	Reference Leg Leakdown The treatment of the dismissal of reference leg leakdown is not thoroughly addressed. The critical design feature is whether there are 2 reactor water level reference legs.	B	The Peer Certification Team observation is reviewed and considered valid. HCGS PSA Revision 1.1 is modified to thoroughly discuss the dismissal of reference leg leakdown as is described below. The HCGS Reactor Pressure Vessel has 4 reference legs. Based on the HCGS PSA Revision 1 Page 3.1-75, the Partial Loss of Reactor Water Level Measurement System special initiator is considered negligible due to the following reasons: a) The loss of any one set of level instruments should not induce a trip. b) The loss of multiple channels could cause a trip and affect auto-initiation of ECCS. Multiple channel loss is unlikely and manual ECCS is still possible. Additionally, EOPs call for RPV flooding if level is uncertain. The concern addressed by the Peer Review Team is if there are 2 or 4 reference legs and that for 2 reference leg plants the likelihood of an induced trip may not be insignificant, therefore, the Partial Loss of Reactor Water Level Measurement System should be included as a special initiator if the plant has only two reference legs. As discussed earlier, Hope Creek has 4 reference legs and based on the Peer Review Team discussion, HCGS assumptions listed above are reasonable. IE is not considered significant.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
IE	13	Initiating Event Frequency The initiating event frequency for each category appears to be based on generic studies. The turbine trip frequency of 1.55/yr is derived from NRC/INEEL study (see P. 3.1-22). The documentation states that the turbine trip initiator is meant to include manual shutdowns also. The NRC / INEEL study does not include manual shutdowns. Therefore, the Hope Creek write-up and analysis should account for this.	B	Completed as specified. HCGS Plant-Specific data for manual shutdowns was collected from the LERs during the time period from 1990 to 1999. This is subsequently updated for the 2003 PRA update with data through June 2003.
IE	16	Except for support system based initiators, the current initiating event frequencies are based mainly on generic data.	B	Plant-specific records reviewed and anticipated transient initiating event frequencies are based on Bayesian update using Plant-specific evidence.
L2	3	The Level 2 CET nodal probabilities can not be reconciled in many cases with the CET fault trees (e.g., CFLA1=0.524 and the CFL FT in App. I, RCB node and the associated FT, etc.). Ensure that the CET nodal fault trees and their basic event probabilities provided as documentation reflect what is actually input into the CETs.	B	Completed for 2003 PSA update. Level 2 is completely updated to calculate the LERF.
L2	8	Sequences with successful Containment Flooding in the CETs are assigned OK releases. These sequences do not appear to address the fact that high releases are likely due to the required DW/RPV venting steps of the containment flooding process.	B	CAFTA Code now use. Containment flood treated explicitly in analysis. Completed for 2003 PSA update.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFICANCE	PLANT RESPONSE OR RESOLUTION
L2	11	The Level 2 HEPs do not appear to account for post-core damage performance shaping factors. For example, the post-core damage containment venting HEP is in the E-3 range (note that the Level 1 venting HEP used is 3E-2).	B	Completed for 2003 PSA update. HEPs were reevaluated based on adverse conditions in the plant.
L2	11	CS for Containment Flooding (HEP & System Performance Adverse Impacts) CS alignment requires access to reactor building for alignment to CST and CST is of limited capacity	B	Completed as recommended. Completed for 2003 PSA update.
L2	19	The containment capability analysis shows that the most likely primary containment failure location by far (probabilistically) is the DW head. The CET nodes do not question whether the primary containment failure occurs in the drywell or the wetwell. These two points appear to indicate that all overpressure containment failure releases go out the drywell head and are, thus, non-scrubbed and large magnitude. This approach seems unnecessarily conservative and different from other Mark I containments.	B	Completed for 2003 PSA update as recommended.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
L2	21	The HCGS EAL procedure is structured such that most or all releases are best labeled as Early (i.e., a general emergency is not declared until failure of radionuclide barriers). Considering another modeling issue that most releases go through the DW head and would tend to be large, the LERF contribution of 5% of core damage appears very low (one would expect 15-25%).	B	Completed for 2003 PSA update. Revised EAL procedure exists and it was used in the Level 2. See Appendix E of the Level 2 evaluation.
L2	22	P. 4.7-2 specifies that Large (High) releases have been determined as "unscrubbed" releases. The CETs are constructed to credit the reactor building effectiveness to reduce magnitude from High to Medium. There currently is no technical basis presented to demonstrate that the HCGS reactor building is adequate to support this reduction.	B	MAAP 4.0.4 runs completed to show RB D.F. Completed for 2003 PSA update.
L2	22	<u>Basis for Definition of Early</u> The Hope Creek EALs were reviewed • The EALs do not lead to the conclusion that Class 2A or 2C releases can be classified as Early • The EALs do not support categorizing Class IBI releases as non-Early Therefore, all accident sequences are considered to be "early".	B	EALs were reviewed and results documented in Appendix to Level 2 Notebook. Completed for 2003 PSA update.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
L2	22	<u>Basis for Definition of Magnitude of Release</u> The documentation says specific CsI release magnitude (> 2.5%) are used to set the radionuclide release magnitudes. The oral presentation indicated that all unscrubbed releases were used to set the definition of high releases. The CETs credit the reactor building for reducing the magnitude. There must be plant specific MAAP cases to support this latter assertion	B	Large is greater than 10% CsI for Level 2 Notebook for basis. Completed for 2003 PSA update.
L2	23	<u>EALs</u> Evaluation of the Hope Creek EALs indicates that all accident sequences in Level 2 would be classified as early. (See Attached excerpt from EALs) Some discretion is available to the ED. His training may influence this discretion. No discussion of this input is available.	B	See Level 2 Notebook for thorough description of EALs and their implications.
L2	24	The EOPs used in the evaluation are the EPG - Rev. 4 based EOPs. These have been superseded on approximately 1/1/99. The use of the latest EOPs would be desirable in the model. This may require an HRA reassessment <u>or</u> it can be performed only on those significant areas affected: • Inhibit ADS in ATWS • RPV injection above MPCWLL • Level 2 • MSIV Reopening perception (EOP 101) <u>Note on Level 1 Analysis</u> The change to the RPV injection at MPCWLL will make Class 2C less important (possibly negligible) and increase the need to address RPV injection after containment breach.	B	Completed for 2003 PSA update.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
QU	8	SBO The relationship of the following procedural items to the required actions for SBO success are not well established. It is believed by the Cert Team that none of these procedural directions are required for the success in the PSA sequence: • opening doors in HPCI/RCIC/inventory rooms/CR • battery load shed • bypass of HPCI/RCIC steam break logic	B	Completed for 2003 PSA update.
QU	8	SBO The SBO evaluation is judged to be conservative in the following areas: • D/G failure probability (random component failure probability) • GT cross tie capability • Battery life assessment of 4 hours (could be 8 hours). No realistic battery calculations are available. This affects the offsite recovery probability success. DC load shedding may extend battery life to 8 hours. • Success criteria should be any single D/G for 4-10 hours	B	Technical basis reviewed for each of the items. PSEG available technical basis included in System Notebook. Results are: • D/G failure probability recalculated with latest data and mission time • Gas turbine effectiveness under LOOP scenarios recalculated • Battery life of 4 hours is all that can be justified • D/G required for successful shutdown is 2 or more

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
QU	8	<u>LOSP Event Sequence Quantification</u> DG failure probability is 5.6E-3 in TE tree. This failure probability is considered very high relative to other PSA analyses and the CCF term of ~ 3E-4. It is judged prudent to: • Reassess the D/G failure probability • Reassess the success criteria for cases with single D/G available - run on simulator - verify with realistic thermal hydraulic model	B	Technical basis reviewed for each of the items. PSEG available technical basis included in System Notebook. Results are: • D/G failure probability recalculated with latest data and mission time • D/G required for successful shutdown is 2 or more
QU	8	<u>EDG-LP Top</u> The top event for EDG evaluation indicates an apparently high failure probability. This appears to have some conservatisms and possibly some errors. The cutsets are shown in the attached NUPRA printout. The Top cutset consists of the following DGS-DGN-FS-DF01 NR-DG-DF-6 TOTAL = 3.11E-4 The numerical value should be verified. In addition, the assumption of no single D/G can be adequate for 4-10 hours is considered too conservative.	B	Technical basis for success criteria is defined in SACS and AC System Notebooks. Model modified to correct errors in 1999 model. Completed for 2003 PSA update. See also other QU-8 responses.
QU	9	<u>LOSP Sequences</u> The dominant contributors to SBO appear to be identified, including all combinations of diesels. (Note triple D/G failures lead to core damage because 1 SACS pump is assumed inadequate.) However, the triple CCF of SACS pumps do not appear to be included in the SBO cutsets or the model	B	Common Cause combinations added to model as recommended. Completed for 2003 PSA update.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
QU	10, 17	There are a substantial number of HEPs that occur in model cutsets if the truncation level is lowered sufficiently or if these HEPs are increased in probability. These multiple HEPs in the same cutset need to be address to determine whether there are dependencies among them that are to be addressed. Guidance/documentation exists that says there is a process to address multiple HEPs. This guidance was not generally followed. A separate study of the multiple HEPs in cutsets was performed, but was performed above the truncation limit. This is judged not adequate. A rerun of the model with HEPs set to 0.1, or their original value if higher indicates a large number of combinations with the potential for dependence. Examples include the following: • Two ventilation actions on both A & C ventilation (Cutset #34 of the attached) • Two non-recovery actions associated with depressurization and ECCS (Cutset #21 of the attached) • Two non-recovery actions both associated with decay heat removal alignments (Cutset #8 of the attached) • Four separate HEPs all in the same cutset (Cutsets #37 and #45 of the attached) • 2 separate HEPs (Cutset #57 of the attached) • 4 separate HEPs (Cutset #174 of the attached) • 3 separate HEPs (Cutset #262 of the attached)	B	Same comment placed under HR, QU and DE elements See response to HR-26.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
QU	11	Missing potential LERF sequences for: • Break Outside Containment (BOC) • Excessive LOCA	B	Now included in 2003 model. Completed for 2003 PSA update.
QU	11	ATWS (see attachment A)	B	Modified to use NRC estimates in NUREG/CR-5500 Vol. 3. Completed for 2003 PSA update.
QU	11	<u>EOPs</u> The EOPs used in the evaluation are the EPG - Rev. 4 based EOPs. These have been superseded on approximately 1/1/99. The use of the latest EOPs would be desirable in the model. This may require an HRA reassessment <u>or</u> it can be performed only on those significant areas affected: • Inhibit ADS in ATWS • RPV injection above MPCWLL • Level 2 • MSIV Reopening perception (EOP 101) <u>Note on Level 1 Analysis</u> The change to the RPV injection at MPCWLL will make Class 2C less important (possibly negligible) and increase the need to address RPV injection after containment breach.	B	See Response to HR-23. HRA completely revamped. Documentation added for all HEPs (123 HEPs).

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
QU	15	Non-Dominant Cutsets A review of non-dominant sequences and their cutsets would be desirable This would investigate potential discrepancies such as that found in T(RA)-23 cutsets 1 through 4 (refer to the attached). It appears that: • SW A is conservatively treated to fail SACS with a single discharge valve closed. AND • SWA fails all instrument air These modeling features appear to be incorrect based on discussion with the PSA group and comparison with the dependency matrix.	B	Completed for 2003 PSA update
QU	15	Remote Local Vent The assessment of remote local vent action has been included in the model. However, the cutsets from the model (see attached) appear to be limited to very specific cutset type related to: • No offsite power • No RHR It does not appear that there are cutsets that include failure of pneumatic supplies coupled with failure of RHR. • Compressors fail and RHR A&B • SW Fails and RHR A&B • SACS Fails These would appear to be candidates for local vent operation but do not show up within the truncation limit.	B	Completed for 2003 PSA update

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
QU	15	<u>Cutset Review</u> IE-S1 * NR-RACS-24-01 * ESF-XHE-MC-DF01 This cutset reflects the failure of all LP ECCS (CS, LPCI) injection valves following a medium LOCA initiating event and (apparently) the failure of condensate long term (greater than 1 hour) after HPCI has depressurized the RPV. The areas of potential investigation include: • The NR-RACS-24-01 definition of the operator action and its quantification are based on an action time of 24 hours for containment heat removal not the 1 hour for this sequence • The success criteria indicate that condensate can be used as a success only if the MSIVs are reopened. It is believed that: a) MSIVs could not be reopened b) Even with MSIVs open, additional hotwell makeup would be required for makeup in a Medium LOCA • The LP interlock miscalibration may be too low in probability • The 1E-10 truncation eliminates other similar contributors	B	PRA completely modified to address each of these items.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
QU	18	There is no procedure for aligning the Salem Unit 3 to recover a loss of offsite power at Hope Creek.	B	Such a procedure does indeed exist. See HC.OP.AB.ZZ-0135.
QU	18	There is no credit for performing DC load shedding to extend the length of the DC batteries.	B	Completed for 2003 PSA update. (See also QU-7, QU-8)
QU	22,23	Truncation The basis for the truncation limit used in the Level 1 PSA of 1E-10 is not presented in the report. However, there was a white paper presented to the Certification Team. (It has been found to be desirable to have a special study of the PSA results as a function of the truncation limit.) This study demonstrates the convergence of the model. The study implies that: • 1E-11 should be used for sequences	B	CAFTA code now used. Not subject to this limitation on fault tree truncation different than sequence quantification. Special truncation study performed and supports the use of 5E-11/yr as the truncation limit. Completed for 2003 PSA update.
SY	5	The RHR system was originally configured to have a single RHR pump to supply a single RHR Hx in each of 2 loops. This is the way the model is structured. PSE&G indicated that the current plant design has the capability to supply each RHR Hx from either of 2 pumps.	B	The cross-tie of either RHR pump to the specific loop is only applicable to the shutdown condition per DCP 4EC-3341. The cross-tie is prohibited in power operation condition. See Ref. HC.OP-SO.BC-0001. We do not take the credit of cross-tie of RHR pumps in full-power operation.
SY	8	Testing and Maintenance unavailability basic events are not found in the Control Equipment Room Supply fault tree.	B	The control equipment room supply is modeled but not used in the Hope Creek PSA. However, the relevant TMs in other room coolers are modeled.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
SY	12	Depressurization The dependency of depressurization on the PCIG is not well described. The following specific items should be addressed: • The accumulators have no technical bases presented to indicate they are adequate for a 24 hour mission time • The simplified drawings do not indicate that non-ADS SRVs have an accumulator	B	The observation is documentation issue due to incomplete information available at the time of peer review. The dependency on PCIG for the Supply Air source to the SRVs is modeled in Fault Tree. The support of 24-hour mission time for the SRVs are provided by the Accumulator, and supplemented by PCIG and ISA systems on a probabilistic basis.
SY	13	The PCIG system backup to the SRV pneumatic supply does not appear to address the need to always open HV-5126A and HV5126A. This is required because if depressurization is needed then the RPV level has dropped below Level 1 and these valves have been isolated – i.e., requiring that they be reopened. This would then require modification to the PCIG fault tree for all non-LOOP and non-LOCA sequences. The impact could be significant if the SRV accumulators are determined not to be sufficient for the mission time of the accidents.	B	In the Hope Creek PSA model, the LOCA-condition always occurs when challenging depressurization. Therefore even in the non-LOOP and non-LOCA events, the HV-5126A and HV5162A will always have to be reopened in the model. Since this flag is set correctly, there is no need to revise the PCIG fault tree.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
SY	15	Systems: Interlock The CS injection valves have a low pressure interlock that must function to allow CS to operate. The logic is of 1-of-2-taken-twice. The transmitters are 90B, 90F, 90K, 90P. The following appears lacking: • The miscalibration HEP of these sensors appears to be too low at 1.65E-6 and no basis is presented. • The system notebook does not discuss this logic or the failure modes, or the quantification of the failure modes. The RAW and FV of the miscalibration of all low pressure interlock transmitters (LPCI and CS) do not appear consistent with the impact these have on the fault trees – see attached.	B	Revised appropriately for 2003 PRA update
TH	8	The success criteria and event tree discussions in Sections 3.1.1 and 3.1.2 of the PSA reference re-opening the MSIVs to recover the PCS. However, the Rev. 4 EPG based HCGS EOPs provided for review only direct re-opening the MSIVs during ATWS scenarios.	B	Completed for 2003 PSA update

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
TH	9	<u>System Success Criteria</u> There is a substantial influence of the assumed system model success criteria on the results. These comments principally apply to SW and SACS success criteria: • System descriptions are missing Ref. 7 of the basis for the success criteria • The SACS single pump success is not included • The failure of 1 of 2 parallel SW discharge valves in "LOOP A" fails all of SACS • Instrument Air appears to be assumed failed given a LOCA signal	B	(See Attachment B)
TH	9	System success criteria is a crucial aspect of the model. These need to have documented basis: • SACS single pumps not adequate to support single D/G • SACS LOOP fails if one discharge valve on SW train fails • Restoration of IAS given LOCA signal not addressed	B	1. The supporting SACS cooling to D1G still needs two SACS pumps. 2. Only the common discharge valve CCF would fail SACS. This is corrected in Rev. 1.1. 3. Restoration of IAS given LOCA signal is addressed using EIAC. See comment on TH-9.

ELEMENT	SUB-ELEMENT	FACT/ OBSERVATION	SIGNIFI-CANCE	PLANT RESPONSE OR RESOLUTION
TH	10	<u>Core Spray Room Cooling</u> The Room Cooling assessment could be used to modify the model: • There is a room cooling set of calculations that indicates that the core spray does not require room cooling. • The CS system notebook write-up, the dependency matrix, and the model include room cooling (and therefore SWS) as a failure mode of the CS. The model could be modified to be less conservative by allowing CS success despite SWS or SACS failures.	B	Completed for 2003 PSA update. CS Room cooling is not required according to Eng. Calc. H-1-GX-NEE-0882 and EG-0047.

Attachment A

ELEMENT QU SUBELEMENT 11

ATWS

The RPS failure probability is an extremely controversial estimate. The basis for the previous estimates used in most PSAs is NUREG-0460 with a value of 3E-5. This probability was subsequently allocated to mechanical and electrical causes based on precursors. The latest NRC sponsored research on this is contained in NUREG/CR-5500 Vol. 3 for BWRs. The results indicate the following:

Common Cause Contributor Type	No Operator Action Credit	Hope Creek with Operator Action Credit
Mechanical	2.1E-6	
Electrical	3.8E-6	
TOTAL	5.8E-6	2.6E-6

This differs from the previous utility group on ATWS evaluation as follows:

Common Cause Contributor	Utility Group on ATWS	NUREG/CR-5500
Mechanical	1E-5	2.1E-6
Electrical	2E-5	3.8E-6
TOTAL	3E-5	5.8E-6

Neither of these are the estimates used in the Hope Creek Quantification

Attachment B

ELEMENT TH SUBELEMENT 9

1. The observation of the first three items are addressed in the rewriting of the SACS/SSWS Success Criteria. See attached.
2. The instrument air will fail only if recovery is also failed, which it always is in the 2003 PSA update.

(1) SACS/SSWS Success Criteria:

There are two SACS/SSWS configurations that can be used to support the cooling of the plant safety systems. The two configurations are the loop operation and 1 SACS/ 2 (1) Hx(s) in each loop (configuration 1-1). The loop operation requires that 2 SACS pumps / 2Hxs are in operation in any one loop and two Service Water (SW) Pumps are also in operation in that loop. The 1-1 configuration requires that 1 SACS/ (2) Hxs, one SW pump in one loop and 1 SACS/1 Hx, one SW pump in the other loop are in operation. The two configurations described here will satisfy the UHS Tech Specs requirement. (See Engineering Calculation EG-0047)

The ECCS systems which can be supported by these two configurations (Operation after 30 minutes at LOP condition) are as follows:

One RHR Heat Exchanger
One IE Panel Chiller (TSC Chiller)
One Control Room Chiller Four RHR
Pump Coolers Four RHR Pump Room
Coolers Four Diesel Engine Coolers
Four Diesel Room Coolers One HPCI
Room Cooler One RCIC Room Cooler
One PCIG Compressor Cooler
Zero CS Room Cooler (CS Room does not need Room Cooling)

For the 1-1 configuration, the loop with 2Hxs in the SACS loop provides cooling to the RHR Heat Exchanger, the other loop (with 1 Hx) provides cooling to the rest of the ECCS heat load.

(2) Fault Tree Description

A. Loop Operation

a. SACS System

Any combination of 2 pumps or 2 heat exchanges in one loop with another pump, heat exchanger or operator failure to align related ECCS valves in the other loop. (Gate GSSA811 and Gate GSSA1060)

Pj(Pk +Operator Error to re-align valves)

Where i, j, are indices for SACS pumps (Heat Exchangers) in loop A (A,C) or Loop B (B, D), k will be B or D for Loop A and A or C for Loop B, and i # j # k

b. SSWS System

1. Failure of the combination of three service water pumps (Gate GSSA 884)

2. Combination failure of both SACS pumps in one loop and 1 SSWS pump in another loop (Gate GSSA1161 and GSSA 1191), i.e.,

Pa*Pc*Pswb, Pa*Pc*Pswd, Pb*Pd*Pswa, Pb*Pd*Pswc

3. Another failure will be the combination of both service water pumps failure in one loop (Because the failure of both SACS heat exchangers) with 1 SACS pump failure in the other loop (Gate GS SA1210), or operator failure to align the valves to the other loop (Gate GSSA1300). i.e.,

(PA +OPERATOR ERROR TO RE-ALIGN VALVES) *PSWB*PSWD,
(PC +OPERATOR ERROR TO RE-ALIGN VALVES) *PSWB*PSWD,
(PB +OPERATOR ERROR TO RE-ALIGN VALVES) *PSWA*PSWC,
(PD +OPERATOR ERROR TO RE-ALIGN VALVES) *PSWA*PSWC,

B. 1-1 Configuration

a. SACS system
For cooling of RHR Heat Exchangers: The cooling can be supplied by either SACS Loop, therefore the failure will be either of the following: 1. Both SACS loops (one pump and one Hx in one loop, and one pump and one Hx in another loop), 2. One pump and one Hx failure in one loop with operator action failure to align valves to another loop. (Item 1 and 2 in Gate GSSA902) 3. Two SACS pumps (Heat Exchangers) fail in one loop with operator failure to align to

another loop. 4. Failure of four SACS pumps Heat Exchangers) (items 3 and 4 in Gate GSSA 1002).

For cooling of the rest of the ECCS systems: Since only the loop with one SACS HX can cool the rest of the ECCS systems, the failure will be Two SACS pumps (Heat Exchangers) in one loop with operator failure to align to another loop or all four pumps (HXs) (GATE GSSA1002).

b. SSWS system

Same as that described in Loop Operation.

Attachment 16

LR-N05-0258
LCR H05-01

HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
TRANSIENT TESTING

Table of Contents

Introduction

This attachment is provided to supplement information in the Hope Creek PUSAR, Paragraph 10.4, Testing. It provides Hope Creek specific information relative to Transient Testing as required by SRP 14.2.1.

Background

In the CLTR (NEDC 33004P-A), GENE provided testing guidelines for Constant Pressure Power Uprates (CPPU) similar to those approved by the NRC staff in ELTR1 (NEDC 32424P-A), but eliminated the recommendation in ELTR1 to perform large transient tests. The Staff concluded that the GENE test program meets the objectives of a suitable test program for CPPU, with exception of the recommendation to eliminate large transient testing. The Staff stated that it would consider, on a plant-specific basis, the need to conduct these tests (i.e., the risk due to potential random equipment failures during the tests) and the additional burden that would be imposed on the licensees.

For Hope Creek, power uprate to 3840 MWt is 15% above current licensed thermal power, and 16.6% above original licensed thermal power. This attachment is submitted to assist the Staff in making the large transient testing determination for Hope Creek.

Summary of Conclusions

As further detailed in this Attachment, PSEG Nuclear LLC concludes that large transient testing is not required for Hope Creek for the reasons set forth below.

1. <u>Plant transient responses are baselined.</u>
   Initial large transient testing was performed during plant start up to determine the integrated plant response after reaching full power operation for the first time. These tests were required to baseline plant response and individual system performance. Unlike initial plant startup, 20 years of operating experience is available to determine plant transient responses. Large transient testing challenges a limited set of systems and components that have an extensive history of safe performance. Therefore, the need to perform additional testing to demonstrate safe operation is not required.
2. <u>Start up test results were satisfactory.</u>
   Start up test results indicated that SSCs could perform their intended functions. For CPPU, the changes in plant conditions are not expected to result in a marked change in plant response. Therefore, the need to perform LTT testing to demonstrate safe operation of the plant is not required.
3. <u>Advanced analytical tools have been employed.</u>
   Advances in analytical tools and modeling techniques have achieved results that provide a high level of fidelity to actual plant responses. Analyses and simulator training will demonstrate that plant shutdown can be safely achieved under CPPU conditions. Therefore, the need to perform LTT to demonstrate safe operation is not required.

4. **CPPU transient analyses conservatively represent plant conditions.**
   Transient analyses at new CPPU conditions conservatively represent plant conditions. No new transients are introduced as a result of CPPU. Therefore, the need to perform additional testing to demonstrate safe operation of the plant is not required.

5. **Safety significance of LTT does not justify imposing severe plant transients.**
   Large transient testing provides information on only a limited number of plant systems that are challenged during testing. This is because the scram and subsequent rapid reduction in power is controlled by normal operator actions. However, LTT events have a negative impact on the station and power grid to which the station supplies a significant base load. The safety significance of LTT testing does not justify the potential negative aspects on plant equipment and the grid.

6. **Testing benefits are not clearly defined.**
   The potential benefit from LTT is not clearly defined. Correct and timely operator response to plant transients and abnormal events (as well as DBAs) is documented through simulator training. Therefore, the need to cycle the plant to re-create simulator scenarios to determine operator response is not required.

7. **Surveillance and post-modification testing assure component response.**
   Surveillance testing and design change verification / testing is performed to ensure correct system and equipment response is available if required. There is no requirement to deliberately place the plant in a transient to uncover potential equipment defects for DBA mitigation. Similarly, there should be no requirement to deliberately induce transient loading events to determine defects.

8. **Hope Creek plant simulator models BOP transients.**
   The Hope Creek plant simulator provides state-of-the-art BOP modeling of transients such that operators will be well trained and experienced in potential plant transients.

9. **Aggregate impact of plant modifications is minimal.**
   The aggregate impact of plant modifications to support CPPU is minimal in that the modifications have minimal safety significance and little impact on overall plant response. In addition, most modifications will have been implemented for one to two full operating cycles in advance of CPPU implementation.

10. **PRA evaluation indicates testing should not be performed in the absence of clear benefits.**
    From an inspection of the Hope Creek model, it does not appear that the reduction in failure probabilities associated with planned transient testing

would fully offset the increase in event frequency due to the guaranteed set of transient changes. From a risk-informed perspective, the testing should be performed only if there are clear benefits that both outweigh the calculated risk and cannot be otherwise obtained through either simulator training or the occurrence of unplanned events.

11. **Plant procedures require reviews of plant transients that result in SCRAMS or ECCS actuations.**
Transient reviews include verifications that safety related and other important equipment functioned properly. Guidelines for post-scram safety assessment include a review of reactor pressure and water level information and an assessment of plant response. Hence, awaiting occurrences of actual plant transients are more analogous to deferred transient testing, rather than elimination of testing requirements.

12. **EPU industry experience indicates plant responses as expected.**
A review of post-EPU plant transients indicated no new thermal-hydraulic phenomena or system interactions were observed following actual turbine trip and load reject events. Plants responded as expected in accordance with their design features. No unexpected conditions were experienced nor were any latent defects uncovered in these events beyond the specific failures that initiated the events.

Transient Testing Evaluations

1.0 Comparison to Hope Creek Startup Test Program

1.1 All power-ascension transient tests performed at ≥ 80% of OLTP

The following transient tests were performed during initial startup, as detailed in the Hope Creek UFSAR.

Initial Transient Test	Power Level	UFSAR Paragraph 14.2	Attachment 2 to SRP 14.2.1
Dynamic Response to Plant Load Swings[1]	100%	12.3.19.3a	Yes
Feedwater Pump Trip	97.4%	12.3.19.3b	Yes
Loss of Feedwater Heating	83.8%	12.3.19.3c	Yes
Closure of All MSIVs	99.6%	12.3.21.3b	Yes
Turbine Trip/Generator Load Rejection	97%	12.3.23.3	Yes
Recirculation Pump Trip	99%	12.3.26.3	Yes

1.2 Tests at lower power invalidated by EPU

No such testing has been identified for the Hope Creek CPPU.

[1] To be performed for EPU in accordance with start-up test specifications, as discussed later in this attachment.

1.3 Attachments 1 and 2 of the SRP 14.2.1

The following tests, included in Attachment 2 of SRP 14.2.1, were not performed during Hope Creek startup at power levels greater than 80%.

Attachment 2 Transient Test	Power Level	Applicable to Hope Creek	Reference
Relief Valve Testing	25%	No	Startup Report
RCIC Functional Testing	25%	No	Startup Report

2.0 Post-modification testing requirements

Numerous modifications have already been implemented at Hope Creek in preparation for increased power levels, including transformer upgrades, moisture separator upgrades, LP turbine replacement, stator winding cooling upgrades, and installation of piping vibration-monitoring equipment. These modifications will have been implemented for approximately two full operating cycles prior to implementation of EPU. Hence, the aggregate impact of these improvements, if any, will not be a factor in power ascension to EPU to any degree beyond that of other non-modified plant equipment.

In addition to the above, the following testing of modifications in support of EPU will be implemented. With the possible exception of the HP turbine, PSEG intends to complete these modifications during RF013, one full cycle prior to proposed implementation of EPU.

Modification	**Post Modification Testing**	**Further Tested by Turbine Trip or other LTT**
No. 2 & 3 Feed Heater Dump Valve Replacements	Controls calibrations Functional performance checks	No
Isolated Phase Bus Duct Cooling Modification	Duct flow rate measurements Thermograph evaluations	No
HP Turbine Replacement	120% rotor speed factory test Transient/steady state data recording Over-speed trip testing	No
EPU I&C Upgrades	Equipment calibrations Component performance measurements	No
Moisture Separator and 5th Point FW Heater Re-Rate	Performance measurements	No
Reactor Coolant and BOP Piping Structural Upgrades (minor hanger upgrades)	Physical inspections NDE	No
Steam Jet Air Ejector A Modification	Parameter measurements at rated flow No chugging at rated flow	No
Condensate Demineralizer and Pre-Filter Mod	Pressure drop measurements at full flow	No

2.1 Aggregate Impact

As can be seen from inspection of the above modifications list, the aggregate impact of these modifications on plant operations is minimal. With exception of the

HP turbine, the modifications are minor adjustments or upgrades to selected BOP components. Proper performance of the impacted components will be established by post-modification testing as listed above.

Aggregate impact of EPU plant modifications, set-point adjustments, and parameter changes will be demonstrated by a test program established for BWR EPU in accordance with startup test specifications as described in PUSAR Section 10.4. The startup test specifications are based upon analyses and GE BWR experience with up-rated plants to establish a standard set of tests for initial power ascension for CPPU. These tests, which supplement the normal Technical Specification testing requirements, are summarized below:

- Testing will be performed in accordance with the Technical Specifications Surveillance Requirements on instrumentation that is re-calibrated for CPPU conditions. Overlap between the IRM and APRM will be assured.
- Data will be taken at points from 90% up to 100% of the CLTP RTP, so that system performance parameters can be projected for CPPU power before the CLTP RTP is exceeded.
- CPPU power increases will be made in predetermined increments of power. Operating data, including fuel thermal margin, will be taken and evaluated at each step. Routine measurements of reactor and system pressures, flows, and vibration will be evaluated from each measurement point, prior to the next power increment. Radiation measurements will be made at selected power levels to ensure the protection of personnel.
- Control system tests will be performed for the reactor feedwater/reactor water level controls, pressure controls, and recirculation flow controls, as applicable. These operational tests will be made at the appropriate plant conditions for that test at each of the power increments, to show acceptable adjustments and operational capability.
- Steam dryer/separator performance will be confirmed within limits by determination of steam moisture content as required during power ascension testing.
- Testing will be done to confirm the power level near the turbine first-stage scram bypass setpoint.

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2.2 *Multiple SSCs*

Functions important to safety that rely on integrated operation of multiple SSCs following plant events (such as plant load swings and loss of feedwater heating) are adequately addressed for Hope Creek, as further delineated in Section 3.0 below.

3.0 Justifications for Elimination of Power-Ascension Tests

The following justifications are provided to demonstrate that the above tests need not be included in the EPU power-ascension testing program.[2]

3.1 *Dynamic Response to Plant Load Swings*

Dynamic responses to plant load swings will be tested under EPU conditions in accordance with Test No. 23 (Feedwater) of the startup test specifications.[3] For information, Test No. 23 is contained in Appendix A to this supplemental information. Since appropriate testing will be performed, no further discussion is provided in this attachment.

3.2 *Feedwater Pump Trip*

Startup Test Objective

Demonstrate the capability of the automatic core flow runback feature of the recirculation system to prevent a low water level scram following the trip of one feedwater pump at near rated power (>95%) conditions.

Start-up Test

Feedwater Pump A was tripped from 97.4% core thermal power on December 2, 1986. Reactor water level dropped from 34.8 inches to 29.8 inches, and stabilized at 34.5 inches. The capacity and response of the two remaining feedwater pumps nearly prevented a recirculation runback during this test, as the Level 4 signal (30 inches) was just reached. The recirculation runback feature functioned correctly as core flow dropped from 98.75% to 45% within 22 seconds. The feedwater pump trip provided a margin to scram of 16.9 inches, which far exceeded the criteria margin of three inches from the low water level scram setpoint of +12.5 inches.

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[2] Throughout this section, comparisons are made between the analyses performed at EPU power levels and actual plant data recorded at current power levels. Where differences appear to be beyond the increases that would be expected from a nominal 15% power increase, those differences are typically explained within the text.

[3] The actual test procedure is not currently prepared, and will be prepared as part of the EPU implementation design change package (DCP). The final test procedure will follow the recommendations of Test No. 23 to the maximum extent practical but may be changed, as necessary, to conform to the plant configuration and expected plant operations.

EPU Transient Analysis Results
The feedwater pump trip event was analyzed at a reactor power level of 3952 MWt. The results of this analysis are shown in Figure 3.2-2 below.

EPU Power Ascension Testing
Feedwater control system testing will be scheduled in accordance with recommendations of Test No. 23 of the start-up test specifications. Test No. 23 is provided in Appendix A to this attachment. This testing is considered sufficient to demonstrate feedwater system capabilities.[4]

Figure 3.2-1 plots plant parameters recorded by GETARS during a Hope Creek event in May 1993, when two feedwater pumps were lost with the plant operating at full power. As can be seen in Figure 3.2-1, reactor vessel level did not reach the low-level trip setpoint of 12.5" (Level 3), and power level stabilized slightly below 50%.[5]

[4] The actual test procedure is not currently prepared, and will be prepared as part of the EPU implementation design change package (DCP). The final test procedure will follow the recommendations of Test No. 23 to the maximum extent practical but may be changed, as necessary, to conform to the plant configuration and expected plant operations.

[5] The May 1993 event was reported by LER 93-003-00. The event was initiated by an electrical (13.8KV) failure that caused a momentary loss of 2 vital buses and 3 non-1E buses. In addition to 2 feed pumps, the electrical transient also tripped a primary and secondary condensate pump, a feedwater heater string, and a recirculation pump. The tripped recirculation pump, along with the full runback of the other recirculation pump, helped to stabilize reactor vessel level and preclude a low-level SCRAM.

Figure 3.2-1

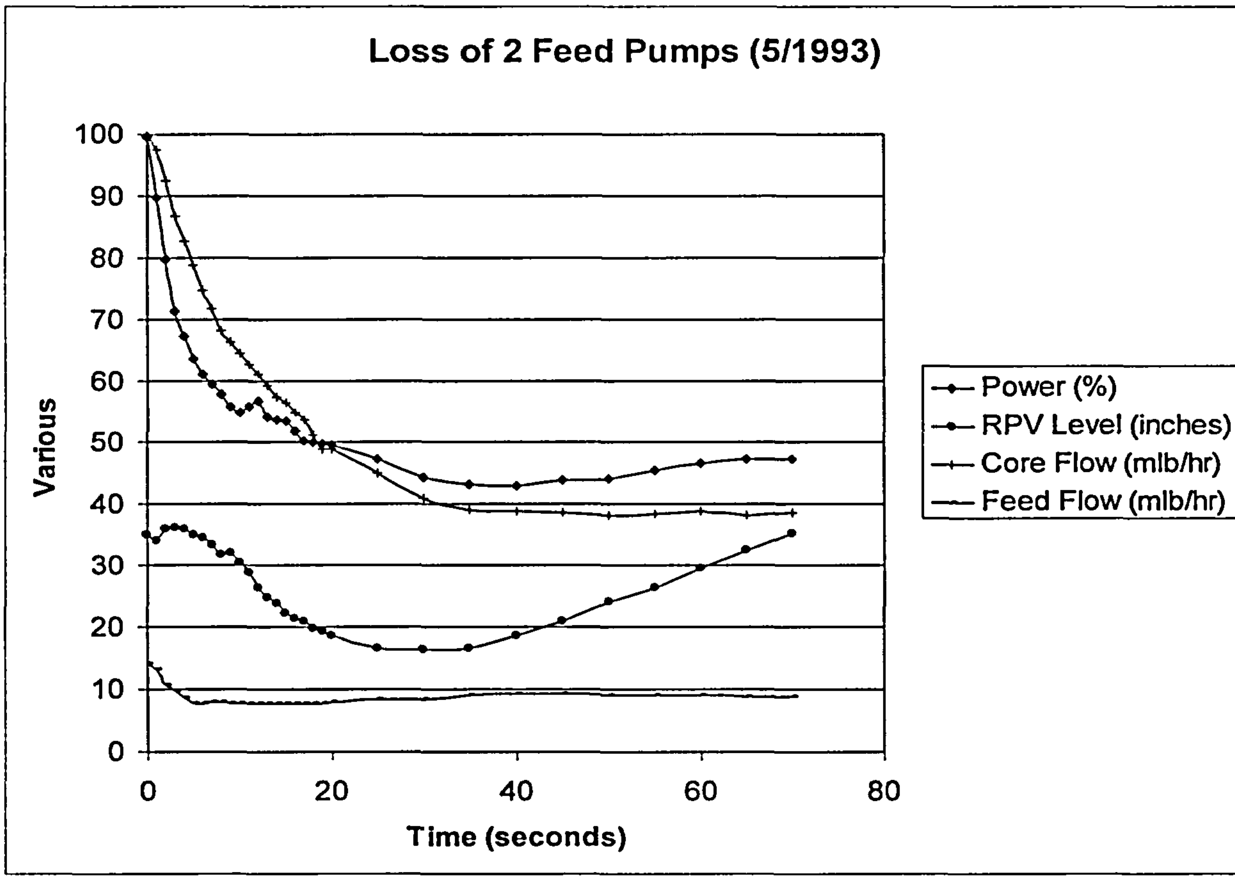
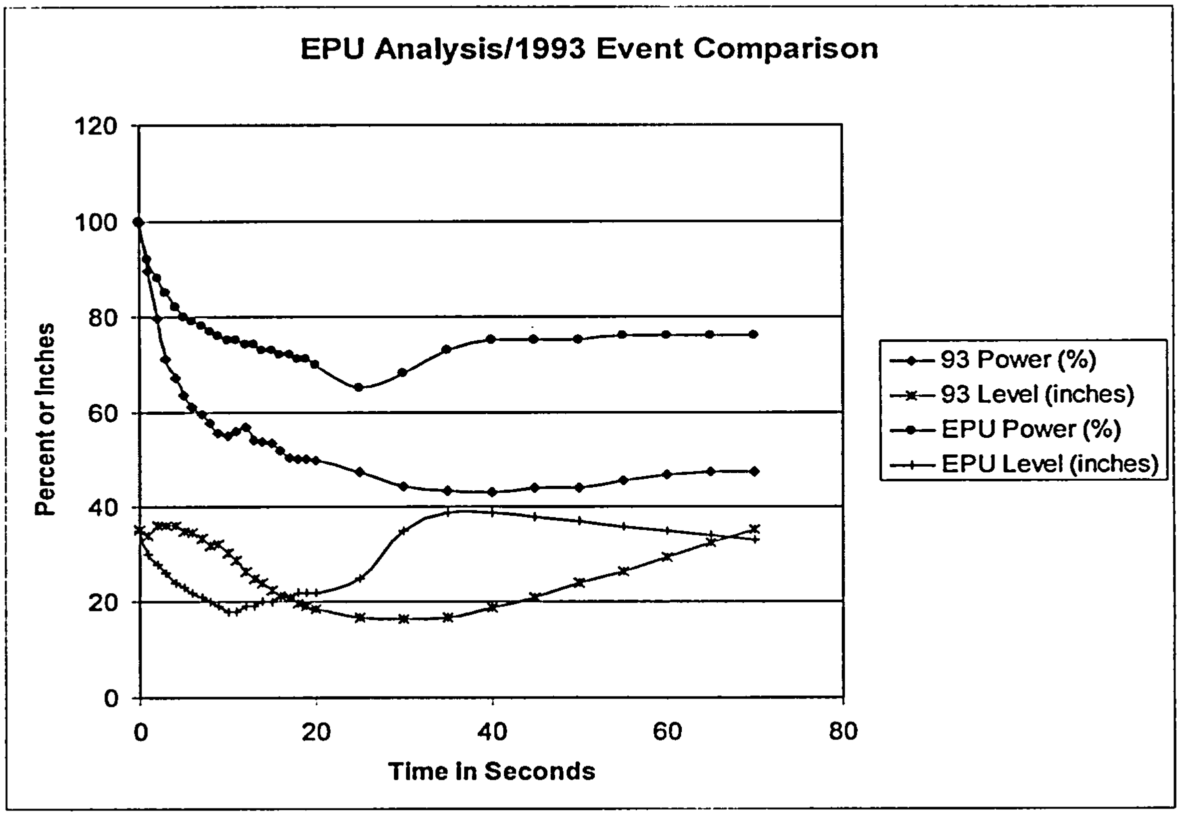


Figure 3.2-2 then compares reactor power and vessel level from the 1993 data with the analysis of Figure 3-21[6] (Single Feedwater Pump Trip) of the EPU transient analyses. As can be seen in Figure 3.2-2, the 1993 event, which included loss of two reactor feed pumps, bounds the EPU evaluation of a single feed pump trip. The 1993 event is bounding both from the standpoint of power level change and reactor vessel level change. While the 1993 event was more than a simple trip of two feedwater pumps (see footnote #5 above), when combined with the margins demonstrated during startup testing, it further demonstrates the robust nature of the Hope Creek systems in responding to a loss of feedwater event.

[6] RPV level of Figure 3-21 is taken outside of the shroud and is converted to inside the shroud for purposes of comparison with the GETARS data.

Figure 3.2-2



Therefore, based on plant historical data and EPU analytical results, the capability of the recirculation system to prevent a low water level scram following the trip of a feedwater pump while operating at EPU power has been established and additional plant testing of feedwater pump trips is not necessary.

3.3 *Loss of Feedwater Heating*

Startup Test Objective

The purpose of this test was to demonstrate adequate plant response to a reduction in feedwater temperature caused by the single failure that will result in the largest loss in feedwater heating.

Start-up Test

A loss of feedwater heating test was conducted on December 3, 1986. The largest loss of feedwater heating by a single failure was initiated by opening the bypass line around the third, fourth, and fifth stage feedwater heaters at 83.8% reactor power and 96.5% core flow. The predicted drop in feedwater temperature at 100% reactor power was approximately 40°F. The actual drop in feedwater temperature was measured to be 21°F, with a resultant increase in thermal power to 86.2% (an increase of about 3%).

The feedwater temperature decrease was well within the predicted, and significantly less than the acceptance criteria of <100°F. The observed 2.7% heat flux increase was less than the allowable Level 2 value of 86.68%. Thermal limit margins were maintained throughout the transient.

Operational Experience Since Start-up
Losses of feedwater heating events periodically occur, often caused by electric power failures. For example, the following three events were reported to the NRC by Hope Creek since 1997:

LER No.	Event Date	Description	Maximum Rx Power	Minimum Feed Temp.	Initiated By
97-010-00	05/27/97	"C" feedwater heater string tripped	105%	Not Reported	UPS circuit card failure
99-009-00	08/27/99	No. 6 heater extraction steam isolation valves closed	100%	366F	Lightning strike
02-003-00	05/13/02	Trip of 6A, 6B, and 6C feedwater heaters	105%	347F	Lightning strike

In each of the above cases, reactor power was reduced and plant conditions were stabilized. There were no safety consequences associated with these events and there were no violations of cladding integrity limits or other fuel design limits.

EPU Transient Analysis Results
The loss of feedwater heating event is performed in the EPU analyses at 100% power and [[

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EPU Power Ascension Testing
As can be seen in the above paragraphs, loss of feedwater heating events occur from time to time and are relatively minor transients, particularly as compared to other potential transients in this attachment. Operators will be well trained on feedwater heater events using the BOP plant simulator, as further discussed in paragraph 4.0. Also, as can be seen in the above LERs, when these events occur they are evaluated for plant responses and safety significance. Consequently, there are no apparent reasons to test feedwater heater losses as part of EPU power ascension.

3.4 *Simultaneous Closure of All MSIVs*

Startup Test Objective
Determine reactor transient behavior resulting from the simultaneous full closure of all Main Steam Isolation Valves.

Startup Test Results

The MSIV full closure test was performed at a reactor thermal power of 99.6% rated (3280MWt) and the main turbine-generator producing 1105 MWe. Initial reactor steam dome pressure was 998 psig, with RPV level at +35 inches. The reactor scram occurred at 0.6 seconds after the second channel of MSIV logic tripped on "MSIVs-not-full-open". MSIVs closed with an average stroke time of 3.56 seconds. Steam dome pressure peaked at 1049 psig at approximately 5 seconds into the transient, with the low-low set "H" SRV opening at 1047 psig (as expected[7]).

Reactor water level reached its minimum value of -46.3 inches at approximately 5 seconds into the transient. Both HPCI and RCIC systems received a low reactor water level auto-initiation signal but only HPCI properly performed its function of injecting water to the vessel. RCIC performance is discussed below.

All Level 1 and Level 2 acceptance criteria were met for this test, except that RCIC failed to develop sufficient head to inject to the core. This was caused by a partial opening of the turbine steam admission valve due to faulty relay contacts. The contacts were subsequently cleaned and adjusted, and RCIC was successfully retested with the reactor at power and pressure.

The following selected parameters were measured during start-up testing:

Parameter	Criteria	Measured
Heat Flux Increase	0.5%	0.0%
Steam Dome Pressure Increase	87.7 psig	51.1 psig
Average MSIV Stroke Time	≥ 3.0 sec.	3.56 sec.
Fastest MSIV Stroke Time	≥ 3.0 sec.	3.28 sec.
Average MSIV Closure Time	≤ 5.0 sec.	3.91 sec.
Slowest MSIV Closure Time	≤ 5.0 sec.	4.16 sec.
Maximum RPV Water Level	< 118 in.	+ 65.0 in.
Minimum RPV Water Level	Not specified	- 46.3 in.

Operational Experience Since Startup

No MSIV full-closure events, intentional or unintentional, have been recorded since the plant startup test. Consequently, initial start up testing at 3280 MWt is the highest reactor power level at which a full MSIV closure has occurred at Hope Creek.

[7] There are two low-low set SRVs at Hope Creek (SRV "H" and "P"). Under the low-low set logic, both valves are armed and initially open at 1047 psig. Once armed, SRV "H" reopens at 1017 psig and SRV "P" reopens at 1047 psig, until the logic is reset.

EPU Transient Analysis Results
The MSIV full closure event was analyzed at a reactor power level of 102% of 3840 MWt. The results are shown in Figure 3-13 (shown in Appendix C) as well as Section 9.1.1 of the PUSAR.

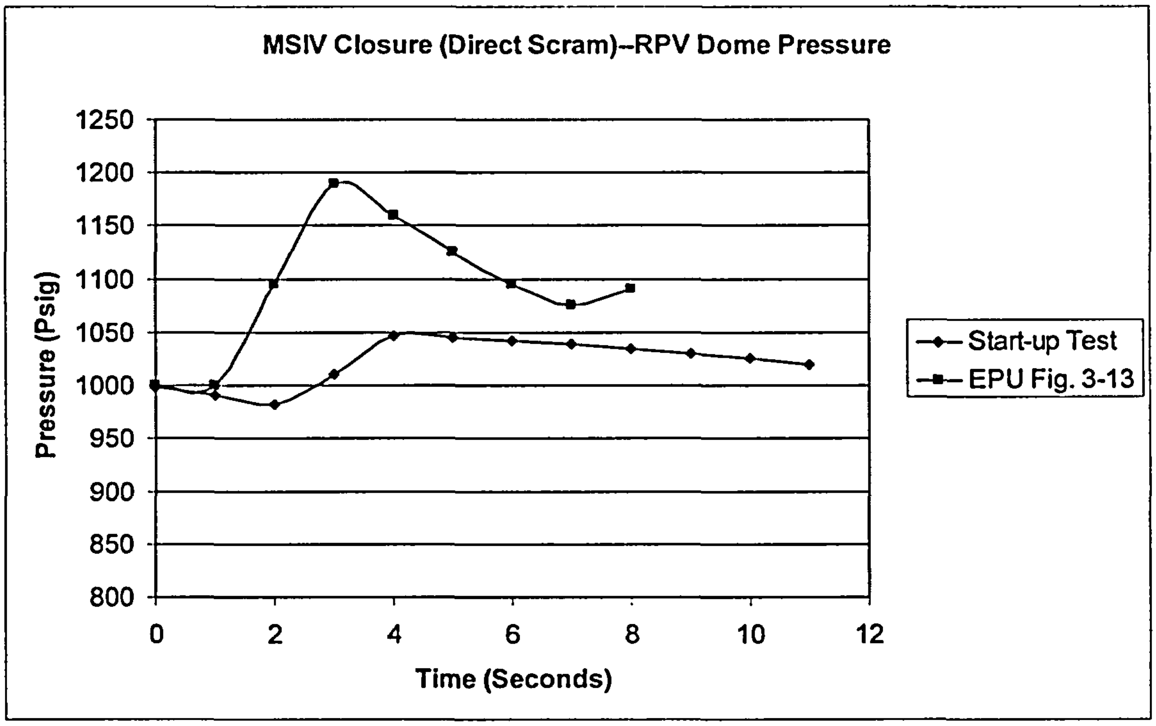
EPU Power Ascension Testing
EPU plant response during power ascension is tested and documented as described in the CLTR/ELTR. MSIV full-closure testing at 100% core power during EPU power ascension testing is not required at Hope Creek because the plant response at CPPU conditions is expected to be similar to the documented response during initial start up testing. The transient analysis performed for the Hope Creek CPPU demonstrates that all safety criteria are met and that [[

]] However, deliberately closing all MSIVs from 100% power will result in an undesirable transient cycle on the primary system that can reduce equipment service life.[8] The transient loading provides no additional plant response information beyond that documented during startup testing and provides no benefit to safety equipment.

As documented in startup test results and reproduced in Figure 3.4-1, RPV dome pressure peaked at 1049 psig during startup testing for this event at 99.6% OLTP (approximately 3280 MWt) in approximately 4 seconds. There are two low-low set SRVs at Hope Creek set to initially open at 1047 psig[9] (the H-SRV opened during the startup test at 1047 psig). However, the Hope Creek EPU transient analysis shows the peak occurs at almost 1200 psig within approximately 3 seconds. While the higher rate of pressure increase is expected due to the higher initial steam flow, the peak is an extremely conservative value. For example, no credit is taken for operation of the low-low set SRVs (SRVs H and P). Even with a single failure, one low-low set valve would open at 1047 psig (± 3%). In the EPU model of Hope Creek, SRVs are set to open at 103% of their nominal setpoint. The analysis is based on SRVs opening as follows: 4 valves at 1141 psig, 5 valves at 1154 psig, and 5 valves at 1164 psig.[10]

[8] As demonstrated during startup and confirmed by analysis, all equipment responses to the transient are within component and system design capabilities. However, placing accident mitigation equipment into service, under maximum loading conditions, uses available service life. Equipment service life should be retained for actual events rather than for demonstration purposes.
[9] See footnote #6 for a description of low-low set operation.
[10] The limiting overpressure event was evaluated with one SRV out of service and direct-SCRAM bypass.

Figure 3.4-1



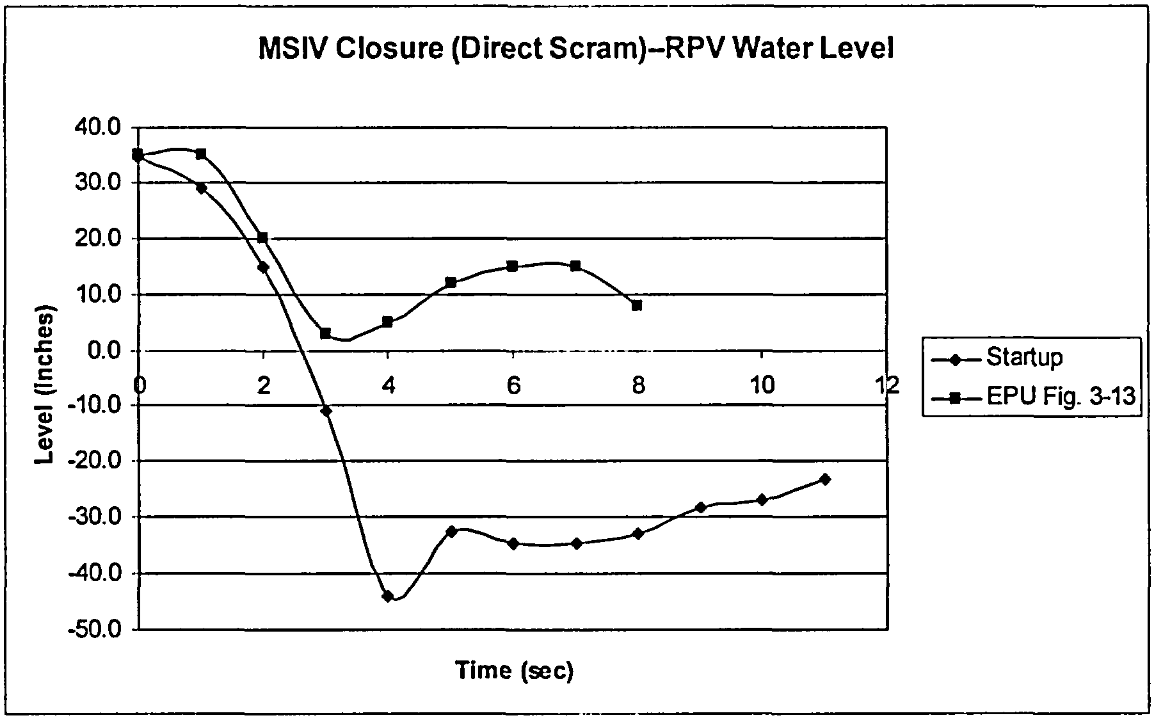
The design pressure of the reactor vessel and reactor coolant pressure boundary remains at 1250 psig. The acceptance limit for pressurization events is the ASME code allowable peak pressure of 1375 psig, which is 110% of the design value. The peak calculated RPV pressures (1229 psig for the direct scram and 1285 psig for the high-flux scram) remain below the 1375 psig ASME limit, and the maximum calculated dome pressures (approximately 20 psig lower) remain below the Technical Specification 1325 psig Safety Limit.[11] The EPU analysis conservatively models SRV opening with a delay and a ramp-open function. Hence, while the EPU transient analysis is satisfactory (maximum vessel pressure for the direct scram of 1229 psig with an initial steam dome pressure at 1020 psig and with one SRV OOS), the actual peak pressure in this event is expected to more closely resemble the 1986 peak. Even with the conservatively calculated peak vessel pressures, however, substantial margins remains available.

Similarly, as shown in Figure 3.4-2 the EPU transient analysis shows level shrink terminates at 3 seconds when the first SRV opens, and therefore does not drop as much as was observed in 1986. Also, in the EPU analysis, recirculation pumps trip at 2 seconds (on high reactor pressure) while the recirculation pumps tripped at 15 seconds (on an ATWS Level 2 signal) during startup. The timing of

[11] For the limiting ASME overpressure evaluation, 1285 psig occurs at the bottom of the vessel with a maximum dome pressure = 1265 psig. The Technical Specification safety limit for steam dome pressure is 1325 psig. Therefore maximum calculated steam dome pressure is acceptable.

the recirculation pump trips in the two events explains most of the differences between the levels in Figure 3.4-2. In any event, RPV level is satisfactory in both instances. With the top of active fuel at 161" below instrument zero, Figure 3.4-2 indicates that a minimum of 10 feet of water will remain above the top of the active fuel during this event either at CLTP or at EPU.

Figure 3.4-2



The operating history of Hope Creek demonstrates that previous transient events occurring at full power remained within expected values. Based on past transient testing, past analyses, and the evaluation of test results, the effects of CPPU RTP on transient response can be analytically determined. In addition, no new design functions in safety related systems were required that would need large transient testing validation for CPPU. No physical modification or setpoint changes were made to the SRVs. No new systems or features were installed for mitigation of rapid pressurization anticipated operational occurrences for CPPU. Instrument setpoints that were changed for CPPU do not contribute to the response to large transient events.

In view of the above, the objective of determining reactor transient behavior resulting from the simultaneous full closure of all Main Steam Isolation Valves can be satisfied for CPPU without LTT testing through a combination of post-modification testing, Technical Specification required surveillances and analysis. In addition, limiting transient analyses are included as part of the reload licensing analysis. The need for re-performing this test at CPPU conditions is not required since plant response is not expected to significantly change from that previously documented at CLTP conditions. Plant experience and analysis demonstrate ade-

quate margin is available in vessel pressure and level limits that demonstrate acceptable reactor transient behavior. Re-performing this transient testing cannot be justified from a safety-significance standpoint if the only benefit is discovering potential hidden defects or latent problems (such as potential hanger failures or potential snubber failures). Piping component failures of this nature were not seen during initial testing and are not expected should testing be re-performed. A failed snubber or hanger will not influence reactor transient behavior and therefore, discovery of these defects are outside of the test objective.

3.5 *Turbine Trip/Generator Load Rejection*[12]

Startup Test Objective

1. Demonstrate the proper response of the reactor and its control systems following trips of the turbine and generator.
2. Demonstrate the capacity of the turbine bypass valves.

Startup Test

On December 6, 1986, a main turbine-generator load rejection was initiated by simultaneously opening the main-generator output breakers with the plant operating at 97% rated thermal power (3194 MWt). Spurious Level-8 trip signals at the start of the transient tripped the feed-water turbines, resulting in starting HPCI and RCIC to maintain vessel level. A subsequent evaluation determined the feed-water control system at Hope Creek to be adequate to maintain RPV water level between Level-2 and Level-8. The recirculation pump drive flow coastdown was found to be slightly above the 4.5 second inertia time constant and was evaluated in a subsequent test. All other acceptance criteria were satisfied.

Operational Experience Since Startup

Since initial startup, a number of turbine trip or generator load reject events have been recorded, including the following examples:

Date	Run No.	Event
08/26/88	88023	Turbine Trip from 100%
10/15/88	88025	Reactor Scram from 100%
08/30/89	89006	Reactor Scram
12/30/89	89007	Load Reject/Generator Lockout
11/04/90	90004	Reactor Scram
05/07/91	91001	Reactor Scram on FWCF
05/15/94	94016	Reactor Scram on L3
10/02/94	94040	Turbine Trip

[12] While turbine trips and generator load rejections are different events in the manner that they are initiated and in the protective devices that must respond, the overall affect on plant response is basically the same. Hence they are treated herein as a single event, including load-rejections that are initiated by a loss of off-site power (LOOP). Hope Creek non-vital buses constantly receive off-site power, hence a LOOP always results in a turbine trip.

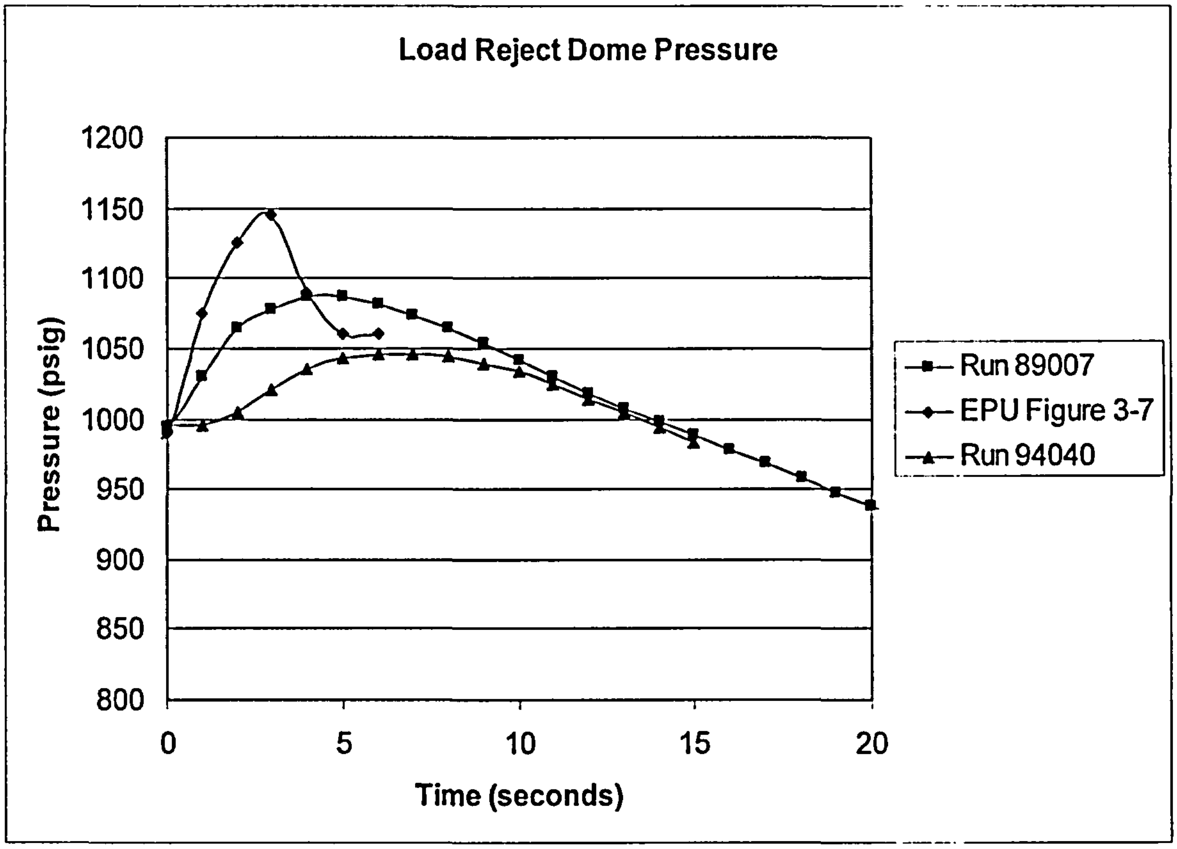
For comparison purposes, parameters from a Load Reject event and a Turbine Trip event (89007 and 94040) were selected and are plotted in Figures 3.5-1 and 3.5-2 along with results from the EPU transient analyses for 100% load rejection.

EPU Transient Analysis Results
A generator load-rejection event was analyzed at a reactor power level of 3840 MWt. The results are shown in transient analysis Figure 3-7 (shown in Appendix D) as well as Section 9.1.1 of the PUSAR.

EPU Power Ascension Testing
Turbine-trip/generator load-rejection testing at 100% core power during EPU power ascension testing is not required at Hope Creek because the plant response at CPPU conditions is expected to be similar to the documented response seen during initial start up testing and historical events tabulated above between 1988 and 1994. The transient analysis performed for the Hope Creek CPPU demonstrates that all safety criteria are met and that [[ ]] However, deliberately causing a load reject and subsequent scram from 100% power results in an unnecessary transient cycle on the primary system that can cause undesirable effects on equipment and grid stability. The transient loading provides no benefit to safety equipment. Therefore, additional load reject / turbine trip testing causing a scram from high power levels is not expected to result in plant response that has not been previously seen nor provide new insight into SSCs performance.

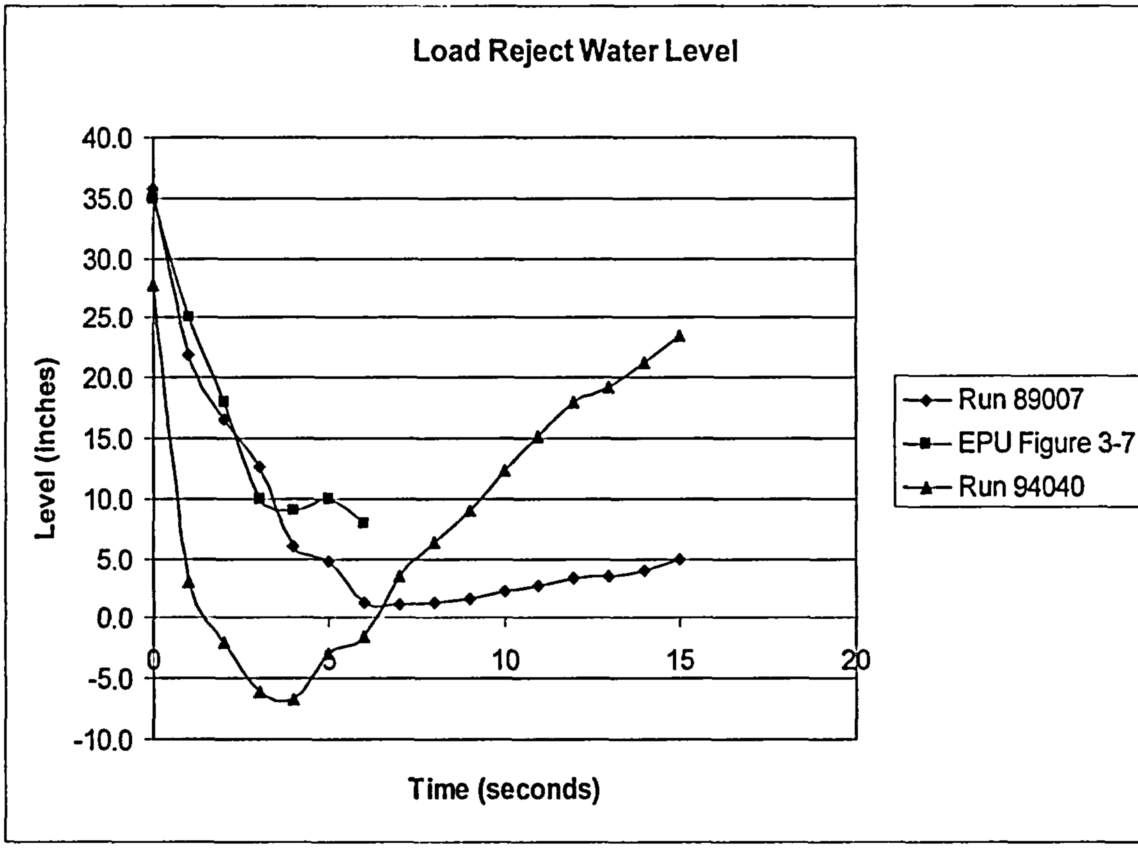
As shown in 3.5-1, RPV dome pressure peaked between 1050 and 1090 psig during the full-power turbine trip/load-rejection events in 1989 (Run 89007) and 1994 (Run 94040). Start up test data indicates that SRVs "H" and "P" opened at 1052 psig. The Hope Creek EPU analysis shows the peak occurs at almost 1150 psig. While the higher rate of pressure increase is expected due to the higher initial steam flow, the peak is a conservative value. For example, no credit is taken for operation of the low-low set SRVs (SRVs H and P), which are set to open (initial opening) at 1047 psig. In the model of the Hope Creek EPU analysis, SRVs are set to open at 103% of their nominal setpoints. Hence, the model expects SRVs to open as follows: 4 valves at 1141 psig, 5 valves at 1154 psig, and 5 valves at 1164 psig. However, since there are two low-low set SRVs at Hope Creek, even with a single failure, one valve would open at 1047 psig (± 3%).

Figure 3.5-1



Since the EPU analysis conservatively models the full opening of the SRVs, there is a slight overshoot, resulting in the 1150 psig peak. Hence, while the EPU transient analysis is satisfactory with a 1150 psig peak (maximum vessel pressure of 1190 psig), the actual peak pressure in this event is expected to more closely resemble the 1989 event, with a maximum value around 1100 psig. Similarly, as shown Figure 3.5-2, the EPU transient analysis shows level shrink terminates at 3 seconds when the first SRV opens, and follows the level observed in either the 1989 or 1994 events. In all cases, RPV level is satisfactory. With the top of active fuel at 161" below instrument zero, Figure 3.5-2 indicates that a minimum of 13 feet of water will remain above the top of the active fuel during this type of event, either at CLTP or at EPU.

Figure 3.5-2



In addition to the above, the operating history of Hope Creek demonstrates that previous transient events from full power are within expected peak limiting values. Based on past transient testing, past analyses, and the evaluation of test results, the effects of the CPPU RTP can be analytically determined. No new design functions that would necessitate modifications and large transient testing validation were required of safety related systems for the CPPU. Instrument setpoints that were changed for EPU do not contribute to the response to large transient events. No physical modification or setpoint changes were made to the SRVs. No new systems or features were installed for mitigation of rapid pressurization anticipated operational occurrences for this CPPU.

In view of the above, transient mitigation capability is demonstrated by post-modification testing and by Technical Specification required testing. In addition, the limiting transient analyses are included as part of the reload licensing analysis. From a safety-significance standpoint, turbine trip/load reject testing cannot be justified in that the transient cycle on the primary plant is undesirable and the potential benefits from such a cycle are not safety-significant. The potential for hidden defects or latent problems that might be uncovered (such as potential hanger failures or potential snubber failures) are not justified on the basis of safety-significance, compared to the potential negative aspects of the transient.

The response of the reactor and its control systems following trips of the turbine and generator has been demonstrated by numerous plant events and shown by EPU analysis to be acceptable. Therefore the objective of this test is satisfied without requiring actual plant transient testing.

3.6 Recirculation Pump Trip

Startup Test Objective

1. Determine transient responses and steady-state conditions following recirculation pump trips at selected power levels.
2. Obtain recirculation system performance data.
3. Verify that cavitation in the recirculation system does not occur in the operating region of the power/flow map.
4. Verify that the feedwater control system can control reactor level without causing a turbine trip/scram following a single recirculation pump trip.
5. Demonstrate the adequacy of the recirculation pump restart procedure at the highest possible power level.
6. Verify acceptable performance of the recirculation two-pump trip circuit.

Start-up Test

Recirculation pump "A" was tripped on December 2, 1986 from 99% reactor power and 98% core flow. Pump "B" was tripped on November 1, 1986 from 75% power and 95% core flow. The pumps were tripped by opening the MG set drive motor breakers from the control room. The margins to scram measured during the pump trips and pump restart satisfied all acceptance criteria.

Pump	Margin to High Water Level Trip Criteria ≥ 3 inches	APRM Margin to Scram on Restart Criteria ≥ 7.5%	Margin to Flow Bias Scram on Restart Criteria ≥ 5%
RR Pump A	14.3 inches	54%	5%
RR Pump B	15.3 inches	67%	32%

Operating Experience

Six events were recorded between 1987 in which one or both recirculation pumps tripped as summarized below:

Recirculation Pump Manual Trip	6/26/1988
Recirculation "A" MG Set Trip	8/05/1988
"B" Recirculation Pump Trip	12/4/1988
"A" Recirculation Pump Removed from Service	10/7/1990
Loss of Both Recirculation Pumps	12/3/1992
Recirculation Pump Trips	3/20/1995

EPU Transient Analysis Results

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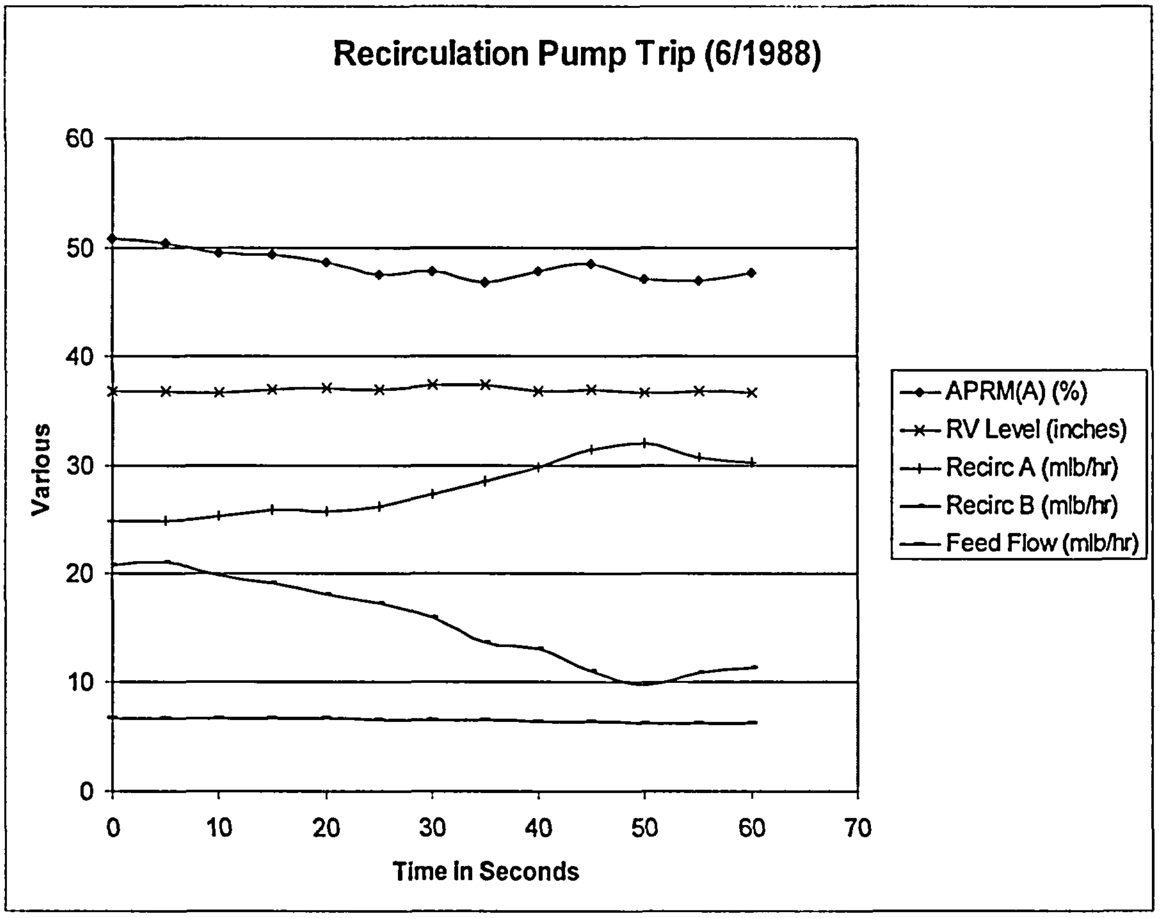
EPU Power Ascension Testing

The results from startup testing and also from the events that have occurred during plant operations indicate recirculation pump trip testing is not considered necessary. For example, Figure 3.6-1 shows GETARS information recorded in June 1988 when Recirculation Pump B tripped during plant operation. As shown in Figure 3.6-1, the impact on the reactor coolant system was relatively minor and well within operating parameters. This is consistent with the original startup testing when recirculation pumps were tripped from full reactor power, where reactor parameters were analyzed with adequate margins to RPS setpoints along with the capability of the feedwater system to prevent high water level trips.

Figure 3.6-1



Therefore, based on plant historical data and GETARS results, acceptable recirculation system and feedwater control has been established (see section 3.2 above); additional plant testing of recirculation pump trips is not necessary.

3.7 Relief Valve Testing

Startup Test Objective

1. Verify that the relief valves function properly and can be manually opened and closed.
2. Verify that the relief valves reseat properly after operation.
3. Verify that there are no major blockages in the relief valve discharge piping.
4. Verify the proper operation of the Low-Low Set relief valve actuation logic system.

Start-up Testing

Safety relief valves (SRVs) were tested with reactor power at 20%, steam dome pressure at 927 psig, and the main turbine secured with steam being routed to the main condenser via the turbine bypass valve. The relief valves were manually opened to verify proper operation and were maintained open for approximately ten seconds to allow plant variables to stabilize and to be recorded for acceptance.

Operational Experience Since Startup

Relief valves are inspected and tested in accordance with Technical Specification requirements. In addition, SRVs have operated satisfactorily during various unplanned events since startup, some of which are discussed in the previous sections of this attachment.

EPU Transient Analysis Results

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EPU Power Ascension Testing

Relief valves will continue to be tested in accordance with Technical Specifications. Since relief valve set-points are not changed and relief valve operations are not impacted by CPPU, there is no need for any additional testing beyond the testing already required by Technical Specifications.

3.8 RCIC Functional Testing

Startup Test Objective

1. Demonstrate the proper operation of the Reactor Core Isolation Cooling (RCIC) system over its expected operating pressure and flow ranges.
2. Demonstrate RCIC system reliability in automatic starting from cold standby when the reactor is at power conditions.

Start-up Testing

On completion of preliminary tests, automatic starts of the RCIC system from cold conditions (shutdown >72 hours) with steam dome pressure at 150 psig and rated conditions were performed to demonstrate system reliability. At rated reactor pressure, the RCIC pump was run at rated flow until turbine and pump temperatures stabilized. RCIC performance was excellent. Rated flow (600 gpm)

was always obtained within the specified time limit (30 seconds) and oscillatory behavior in the controlled process variables was essentially nonexistent.

Operational Experience Since Startup
During operational events since startup, RCIC has provided acceptable performance when required to function by operational events.

EPU Reactor Core Isolation Cooling System Evaluation
The Reactor Core Isolation Cooling (RCIC) system evaluation for Hope Creek CPPU addressed system performance and hardware, net-positive suction head, core cooling for limiting loss of feedwater events, and inventory makeup (avoidance of operational level 1). All topics were found acceptable, as detailed in Section 3.9 of the PUSAR.

The RCIC system is required to maintain sufficient water inventory in the reactor to permit adequate core cooling following a reactor vessel isolation event accompanied by loss of flow from the FW system. The system design injection rate must be sufficient for compliance with the system limiting criteria to maintain the reactor water level above top of active fuel (TAF) at the CPPU conditions. The RCIC system is designed to pump water into the reactor vessel over a wide range of operating pressures. As described in Section 9.1.1, this event is addressed on a plant specific basis. The results of the Hope Creek plant specific evaluation indicate adequate water level margin above TAF at the CPPU conditions. Therefore, the RCIC injection rate is adequate to meet this design basis event.

An operational requirement is that the RCIC system can restore the reactor water level while avoiding Automatic Depressurization System (ADS) timer initiation and MSIV closure activation functions associated with the low-low-low reactor water level setpoint (Level 1). This requirement is intended to avoid unnecessary initiations of safety systems. The results of the Hope Creek plant specific evaluation indicates that the RCIC system is capable of maintaining the water level outside the shroud above nominal Level 1 setpoint through a limiting LOFW event at the CPPU conditions. Thus, the RCIC injection rate is adequate to meet the requirements for inventory makeup.

For the CPPU, there is no change to the normal reactor operating pressure and the SRV setpoints remain the same. There is no change to the maximum specified reactor pressure for RCIC system operation, [[

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The Loss of Feedwater Flow (LOFW) transient was analyzed for CPPU. During a LOFW transient and assuming an additional single failure of HPCI, reactor water level is automatically maintained above the top of the active fuel (TAF) by the RCIC system, without any operator action. Because of the increased decay heat from the CPPU, slightly more time is required for the automatic systems to re-

store water level. Operator action is only needed for long-term plant shutdown. After water level is restored, the operator manually controls water level, reduces reactor pressure, and initiates RHR shutdown cooling. These sequences of events do not require any new operator actions or shorter operator response times. Therefore, the operator actions for a LOFW transient do not significantly change for the CPPU.

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EPU Power Ascension Testing

RCIC testing during EPU power ascension testing is not required because the EPU changes do not have a significant impact on the RCIC system. Specifically, system pressures, temperatures, flow rates, and timing requirements remain unchanged from CLTP requirements. Therefore, RCIC testing would not provide any new data, particularly with regard to overall plant safety-significance. RCIC testing in accordance with Technical Specification requirements remains a sufficient demonstration of RCIC capability.

4.0 Operator Training/Large Transient Simulations

In preparation for Extended Power Uprate, the Hope Creek plant simulator was upgraded by implementation of the THOR-BOP advanced thermal hydraulics model. Use of THOR-BOP was initiated in late 2004 and is currently in use at Hope Creek. The THOR-BOP model applies state-of-the-art fidelity to secondary system performance during simulation of plant transients at Hope Creek.

Recent introduction of high power processors now provides simulator users the option of using high-fidelity models to model secondary plant performance. THOR models have been recently installed in a variety of other nuclear stations, including Surry and Davis Besse. Using the THOR models for the BOP applies the high fidelity of the RCS models to the secondary plant and provides tight coupling of primary and secondary plant systems. Hope Creek uses THOR-BOP for all high energy, two phase systems in the secondary plant, including turbine, extraction steam, MSRs, condenser, condensate, feedwater, feedwater and heater vents and drains.

The following steam/water cycle flow paths are simulated using the advanced secondary model. The advanced model is of sufficient fidelity to faithfully represent the plant in normal, off-normal, and transient conditions. All thermal hydraulic equations include conservation of mass, momentum, and energy at all times in every scenario.

STEAM CYCLE	WATER CYCLE
To steam jet air ejectors	Hot-wells
To off-gas preheaters	Condensate to and including primary pumps
HP steam to RFPTs, including turbine exhaust to condenser	Condensate from primary pumps to secondary pumps
LP steam to RFPTs	Condensate from secondary pumps to LP feedwater heaters and drain coolers
Hotwell heating steam supply	Condensate flow from LP feed-water heaters to RFPs
Steam to HP turbine	Feedwater flow from RFPs to HP feedwater heaters
Crossover steam to MSRs	Feedwater from HP heaters to F011 (last feedwater valve to RPV
LP steam to LP turbines	Minimum recirculation flow lines for PCP, SCP, RFP including RFP warm-up lines
All extraction steam	Hydrogen water injection system
Main condenser	
Condenser air removal/off-gas system to vent stack	
Auxiliary steam system	

As part of THOR-BOP implementation, transient and accident response testing was performed to include all transient tests listed in ANSI/ANS 3.5-1993 along with a selected set of plant transients using existing plant data. The benchmarking of the simulator has been completed in accordance with the current plant configuration, and will be revised or updated when CPPU modifications are installed. Consequently, plant transients will be simulated in accordance with CPPU analyses and operators will be thoroughly trained and experienced on potential transients in advance of proposed CPPU implementation.

5.0 Large Transient Testing Risk Assessment

The NRC in RG 1.174 has identified that risk-informed decision making can be effectively used in licensing applications. In support of the risk-informed decision making, RG 1.174 has identified acceptance guidelines for characterizing the risk inputs using the risk metrics of the change in core damage frequency (CDF) and the change in large, early release frequency (LERF).

Using PRA tools and the Hope Creek PRA model (as revised for CPPU), PSEG conducted a review of risks associated with certain large transient tests. The review calculated risk metrics for ΔCDF and ΔLERF associated with the change from the current licensed thermal power (CLTP) to the constant pressure power uprate

(CPPU) (see PUSAR Section 10.5).[13] In addition, PSEG also compared CPPU risks between two assumed testing conditions: (1) the CPPU condition with planned transients (i.e., large transient testing); and, (2) the CPPU condition except with no planned large transient events. These latter comparisons are discussed below.

The large transient testing program is modeled here as two tests from full CPPU power. One test is an MSIV closure; the other test is a Generator Load Rejection modeled here as a turbine trip. The CPPU PRA model is modified to calculate the risk associated with these tests if each test is accounted for in the initial startup. The modified CPPU model calculates the annualized risk for the initial year of CPPU operation. This annualized risk can then be compared with the annual risk calculated using the base CPPU PRA model.

Using the zero maintenance model[14] for internal events, the change in the CDF risk metric, ΔCDF, due to large transient testing is 4.32E-6/yr and the change in the LERF risk metric, ΔLERF, is 1.77E-07/yr.

The results for CDF and LERF annualized for year 1 using the two CPPU models are provided in the table below:

Case A – CPPU configuration with no assumed full power tests

Case B – CPPU configuration with the assumed MSIV closure and Generator Load Rejection full power tests included.

In addition, the change in the risk metrics is also included in the table.

Condition	CDF (/yr)	LERF (/yr)
A. CPPU (2005B) Zero Maintenance Turbine Trip Freq. = 1.25/yr MSIV Closure Freq. = 0.0269/yr	6.08E-06	1.59E-07
B. CPPU (2005B) Zero Maintenance with added initiators for full power tests Turbine Trip Freq. = 2.25/yr MSIV Closure Freq. = 1.0269/yr	1.04E-05	3.36E-07
Change in Risk Metrics (ΔRisk Metric)	4.32E-06 (+71%)	1.77E-07 (+111%)

[13] PRA evaluations performed for CPPU are discussed in PUSAR Section 10.5.

[14] The "zero" maintenance models are the applicable PRA model results for CLTP and CPPU when the maintenance and test unavailabilities are set to zero, that is declared operable, i.e., key safety equipment is not in either a test or maintenance outage.

The changes in CDF and LERF associated with performing both tests would place the risk increase in Region II of the RG 1.174 acceptance guideline. Region II is characterized as a region of "small" changes.

It is also noted that there are potential adverse impacts associated with the initial year of operation following a major plant change. This "break in" period associated with the theoretical "bathtub" reliability curve may be manifested in higher failure rates for any "new" CPPU components or control systems. From this standpoint, the risk calculated above may be slightly optimistic.

However, in the case of planned transient tests, there are certain failure probabilities that can also be reduced. The primary categories (in addition to the test and maintenance which are already accounted for) are human error probabilities (HEP) and certain environmental factors. For example, several potential erroneous operator-actions could be reduced if the operators are expecting the transient and are recently trained and briefed on the spectrum of possible results. In addition, the test could be performed under less severe environmental conditions than those anticipated in the design basis and event modeling. These various improvements would reduce the conditional CDF for the specific event, given the occurrence of the transient.

Nevertheless, from an inspection of the Hope Creek model, it does not appear that these improvements would fully offset the increase in event frequency due to the guaranteed set of transient changes. From a risk-informed perspective, the testing should be performed only if there are clear benefits that both outweigh the calculated risk and cannot be otherwise obtained through either simulator training or the occurrence of unplanned events.

Hope Creek may, in the future, experience events that approximate the conditions imposed by the identified tests. It is noted that when actual plant transients occur that result in a reactor scram or emergency core cooling system (ECCS) actuation, Hope Creek procedures and guidelines direct actions to be taken to review the events. These actions include verification that safety related and other important equipment functioned properly. Guidelines for post-scram safety assessment include a review of reactor pressure and water level information and an assessment of plant response. Hence, awaiting occurrences of actual plant transients is more analogous to deferred transient testing, rather than elimination of testing requirements.

6.0 Post EPU Industry Experience

A review of industry events that occurred at greater than original power levels at stations of similar design as Hope Creek (i.e. BWR-4 with Mark 1 containments) resulted in the following examples of plant response to MSIV closure and load reject events. As indicated in the examples below, the plants responded as expected in accordance with their design features. No unexpected conditions were experienced

nor were any latent defects uncovered in these events beyond the specific failures that actually initiated the events.

Edwin I. Hatch Nuclear Plant - 13% Approved Power Uprate

LER 99-05

On May 5, 1999, Hatch Unit 2 was at 98.3% of rated power (2716 CMWT). At that time, the turbine tripped when the main generator tripped on a ground fault. The reactor scrammed and the reactor recirculation pumps tripped automatically on turbine control valve fast closure caused by the turbine trip. The reactor feed water pumps maintained water level higher than eight inches above instrument zero. No safety system actuations on low level were received nor were any required. Pressure reached a maximum value of 1124 psig. Plant and system responses were as expected.

LER 2000-004

On July 10,2000, Hatch Unit 1 was at 99.7 percent rated thermal power (2754 CMWT). At that time, the main turbine tripped when the vibration instrument on the main generator exciter outboard bearing failed and produced a false high-bearing vibration signal. The reactor automatically scrammed and the reactor recirculation pumps automatically tripped on turbine stop valve fast closure caused by the main turbine trip. All systems functioned as expected and given the water level and pressure transients caused by the turbine trip and reactor scram. Vessel water level was maintained above the top of the active fuel throughout the transient and never decreased to the Level 3 actuation set-point. No safety system actuations were received nor were any required.

LER 2001-02

On March 28, 2001, Plant Hatch Unit 1 was at 100 percent rated thermal power (2763 CMWT). At that time, the reactor automatically scrammed on turbine control valve fast closure caused by a main turbine trip. The main turbine tripped when actuation of phase two and phase three differential relays monitoring a unit auxiliary transformer resulted in actuation of a lockout relay. Actuation of this lockout relay generated a direct turbine trip signal and the main turbine tripped per design.

Reactor Feedwater Pumps recovered reactor vessel water level within 30 seconds of the scram. As a result, the HPCI and RCIC system low water level initiation signals cleared before either system could inject makeup water to the reactor vessel. Vessel pressure reached a maximum value of 1127 psig after receipt of the scram. All systems functioned as expected and per their design given the water level and pressure transients caused by the turbine trip and reactor scram. Vessel water level was maintained well above the top of the active fuel throughout the transient.

Brunswick Steam Electric Plant – 20% Approved Power Uprate

LER 2003-01

On January 12, 2003, Brunswick Steam Electric Plant Unit 1 was operating at 94% rated thermal power. Decreasing reactor coolant level due to a reactor feed water pump turbine trip resulted in the actuation of the reactor protection system, and a Group 2 and Group 6 primary containment isolation valves closures. After the plant trip, the (4) emergency diesel generators started due to an invalid signal generated by switchyard equipment. In addition, the Reactor Core Isolation Cooling system was manually operated to maintain coolant level in the reactor vessel. The loss of the reactor feed water pump was attributed to insufficient lube oil pressure margin in the bearing oil header.

The required equipment responded as designed and the Group 2 and 6 valves isolated. All control rods fully inserted into the core. However, a power circuit breaker in the 230 kV electrical power system did not open initially as designed to separate the main transformer and generator from the grid. This caused an invalid signal that resulted in the start of the emergency diesel generators after the turbine generator trip.

LER 2003-04

On November 4, 2003, Brunswick Steam Electric Plant Unit 2 was operating at approximately 96% of rated thermal power when a generator/turbine trip occurred due to loss of generator excitation. Approximately three seconds into the voltage transient, the Unit 2 generator/turbine tripped, resulting in RPS actuation. The voltage decrease also resulted in PCIS Valve Group 1 (Main Steam Isolation valves (MSIVs), Main Steam Line Drain valves, and Reactor Recirculation Sample valves), Group 3 (Reactor Water Cleanup isolation valves), and Group 6 (Containment Atmosphere Control/Dilution, Containment Atmosphere Monitoring, and Post Accident Sampling System isolation valves) isolations.

All control rods fully inserted into the core. Plant response to the transient also resulted in High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) System actuations on low reactor pressure vessel (RPV) coolant level, with injection into the RPV. All four Emergency Diesel Generators (EDGs) automatically started but did not load because electrical power was not lost to the emergency buses.

APPENDIX A

Test No. 23; Feedwater System (5 pages)

Item	Subject	Description
1	Purpose	1. Verify the feedwater control system has been adjusted to provide acceptable reactor water level control over EPU operating conditions and subcooling changes, 2. Confirm the feedwater flow calibration and 3. Determine if the maximum feedwater runout capability is compatible with the licensing assumptions for the EPU conditions.
2	Applicability	Mid-cycle on-line and post refueling outage EPU implementation phases.
3	Description	Feedwater Control System Testing **Note:** This testing may produce core power excursions due to the feedwater addition. The power levels of these operational transients may exceed the steady-state power level of the test condition. These excursions are expected in the EPU power ascension test program. For tests calling for level setpoint changes, at each test condition reactor water level setpoint changes are introduced into the feedwater control system in accordance with the following setpoint change sequence. [[ ]] The normal feedwater control system mode is three-element control, with single element control only being used for temporary backup situations. The feedwater control system in three-element control mode should be adjusted, not only for stable operational transient level control (i.e., decay ratio), but also for stable steady-state level control (i.e., minimize reactor water limit cycles). In single element

Item	Subject	Description
		control mode, the system adjustments must achieve the operational transient level control criteria, but for steady state level control the temporary backup nature of this mode should be considered. For tests calling for manual flow step changes, at each test condition the feedwater control system is placed in a manual/auto configuration (i.e., one feedwater pump in manual and the other in automatic controlling water level). Preferably the flow step changes are made by inserting the step demand change into the feedwater pump controller in manual or alternately by changing the setpoint of that controller in accordance with the following setpoint change sequence expressed in percent of LPU rated feedwater flow. After completion of testing on one controller, the manual/auto configuration is switched and the sequence is repeated on the other controller. [[ ]] <u>Feedwater Flow Calibration</u> Feedwater flow data from the flow elements will be compared against known flow source information. Refer to SIL-452 (Ref. 3) for calibration information on feedwater flow element transmitters. [[ ]] <u>Maximum Feedwater Runout Capability</u> During the EPU power ascension, pressure, flow and controller data is gathered on the feedwater system performance. This measured data is compared against expected values, which are based on information such as pump performance curves, turbine speeds, feedwater system flows and vessel dome pressure. The pump performance curves, adjusted according to operating data, are used to determine the turbine speed corresponding to the maximum feedwater runout flows at the reactor vessel pressures specified in the cycle specific OPL-3. Since the maximum flows stated in OPL-3 are used as transient analyses assumptions, the OPL-3 maximum

Item	Subject	Description
		feedwater runout flows must not be exceeded. For good level control system performance it is desirable to be able to achieve the level 2 criteria. System control adjustments (i.e., turbine speed loops, flow/speed limiters, feedwater control system, etc.) are set to prevent the feedwater pumps from exceeding their maximum allowable flows, and still allow the desirable performance.
4	Test Data Acquisition	Operating Parameters to be Monitored During Power Ascension Analog variables that should be recorded for each feedwater control system test are: 1. Narrow range vessel water level 2. Vessel dome pressure 3. APRM 4. Feedwater pump controller output (in manual) 5. Feedwater pump controller output (controlling level) 6. Total feedwater flow 7. "A" Feedwater pump output 8. "B" Feedwater pump output 9. "C" Feedwater pump output 10. Condensate booster pump discharge pressure * 11. Condensate pump discharge pressure * 12. Condensate pump suction pressure * * These variables permit evaluation of the entire feedwater / condensate system during these transient tests. Monitoring these specific parameters is a recommendation and not a requirement. If the signals are not available, alternatives may be considered during the development of the detailed test procedure.
5.1	Test and Test Conditions	Test Point: Three-Element Test: 1. Level Setpoint Changes Test Conditions: A. 90% CLTP. B. 100% CLTP. C. Each ≤ 5% CLTP increment up to maximum EPU power. **Note:** Final test condition for level setpoint change testing in three-element is LPU (+0/-5%). Recirculation Mode: Manual
5.2	Test and Test Conditions	Test Point: Single Element

Item	Subject	Description
		Test: 1. Level Setpoint Changes Test Conditions: A. 90% CLTP. B. 100% CLTP. C. Each ≤ 5% CLTP increment up to maximum EPU power. **Note:** Final test condition for level setpoint change testing in single element is LPU (+0/-5%). Recirculation Mode: Manual.
5.3	Test and Test Conditions	Test Point: Normal Mode Test: 1. Manual Flow Step Changes Test Conditions: A. 90% CLTP. B. 100% CLTP. C. Each ≤ 5% CLTP increment up to maximum EPU power. **Note:** Final test condition for manual flow step change testing is LPU (+0/-5%). Recirculation Mode: Manual
5.4	Test and Test Conditions	Test: 1. None – Feedwater Flow Calibration Data Collection. Test Conditions: A. 90% CLTP. B. 100% CLTP. C. Each ≤ 5% CLTP increment up to maximum EPU power.
5.5	Test and Test Conditions	Test: 1. None – Maximum Feedwater Runout Data Collection. Test Conditions: A. 90% CLTP. B. 100% CLTP. C. Each ≤ 5% CLTP increment up to maximum EPU power.
6.1	Level 1 Criteria	The decay ratio must be less than 1.0 for each process variable that exhibits oscillatory response to feedwater system changes.
6.2	Level 1 Criteria	The maximum feedwater runout capacity, as determined from measured data in comparison to expected values and adjusted to the specified pressure, shall not exceed the value specified in the OPL-3

Item	Subject	Description
		for the cycle specific feedwater controller failure-maximum demand analysis.
7.1	Level 2 Criteria	a) The decay ratio of any oscillatory variable must be ≤ 0.25. b) For the manual flow step changes, the dynamic flow response for each feedwater turbine to the step disturbances shall be: (1) Maximum time to 10% of a step disturbance ≤ 1.1 seconds (2) Maximum time from 10% to 90% of a step disturbance ≤ 1.9 seconds (3) Peak overshoot (% of step disturbance) ≤ 15% (4) Settling time, 100% ± 5% of step disturbance ≤ 14 seconds c) For manual flow step changes, the average rate of response (computed between 10% and 90% of response) of the feedwater flow to the step flow demand shall be between 10% and 25% of rated pump flow per second.
7.2	Level 2 Criteria	Feedwater flow capability should be at least 5% greater than the normal steady state operating feedwater flow rate at full EPU power.

APPENDIX B

Figure 3-1 (Feedwater Controller Failure) and Figure 3-3 (Feedwater Controller Failure with RFWT) from the EPU Transient Analysis

Figure 3-1: Feedwater Controller Failure

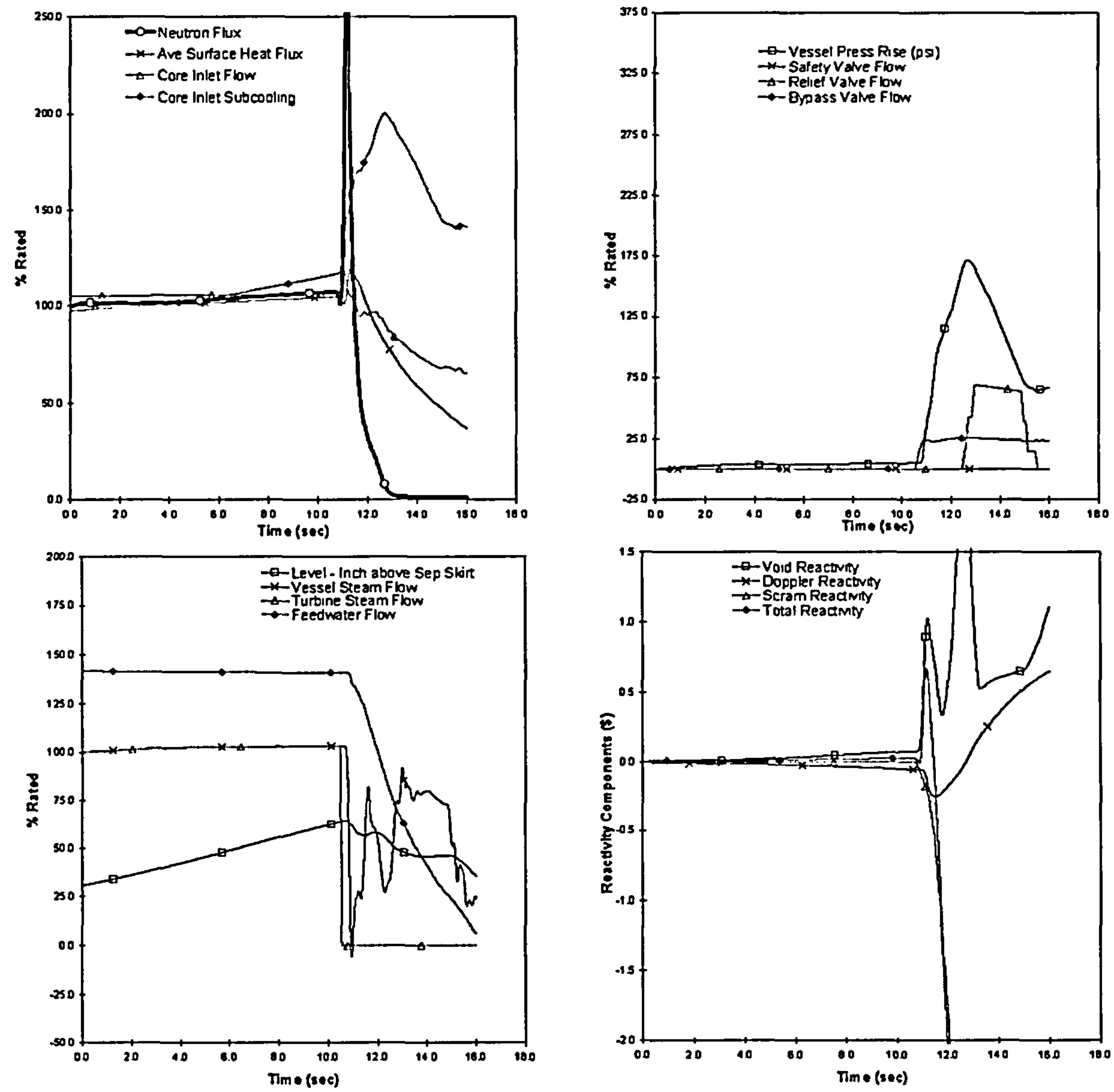
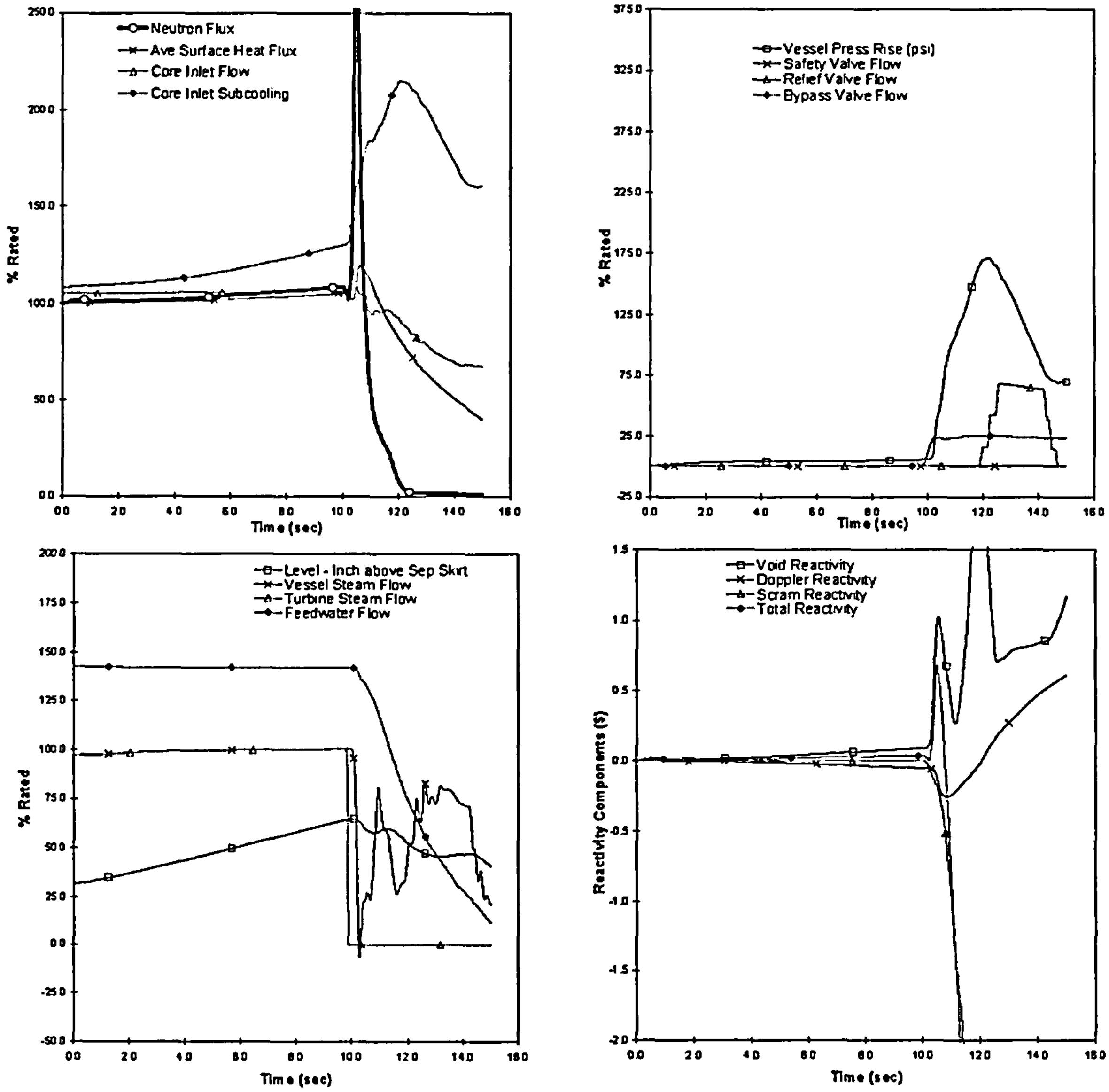


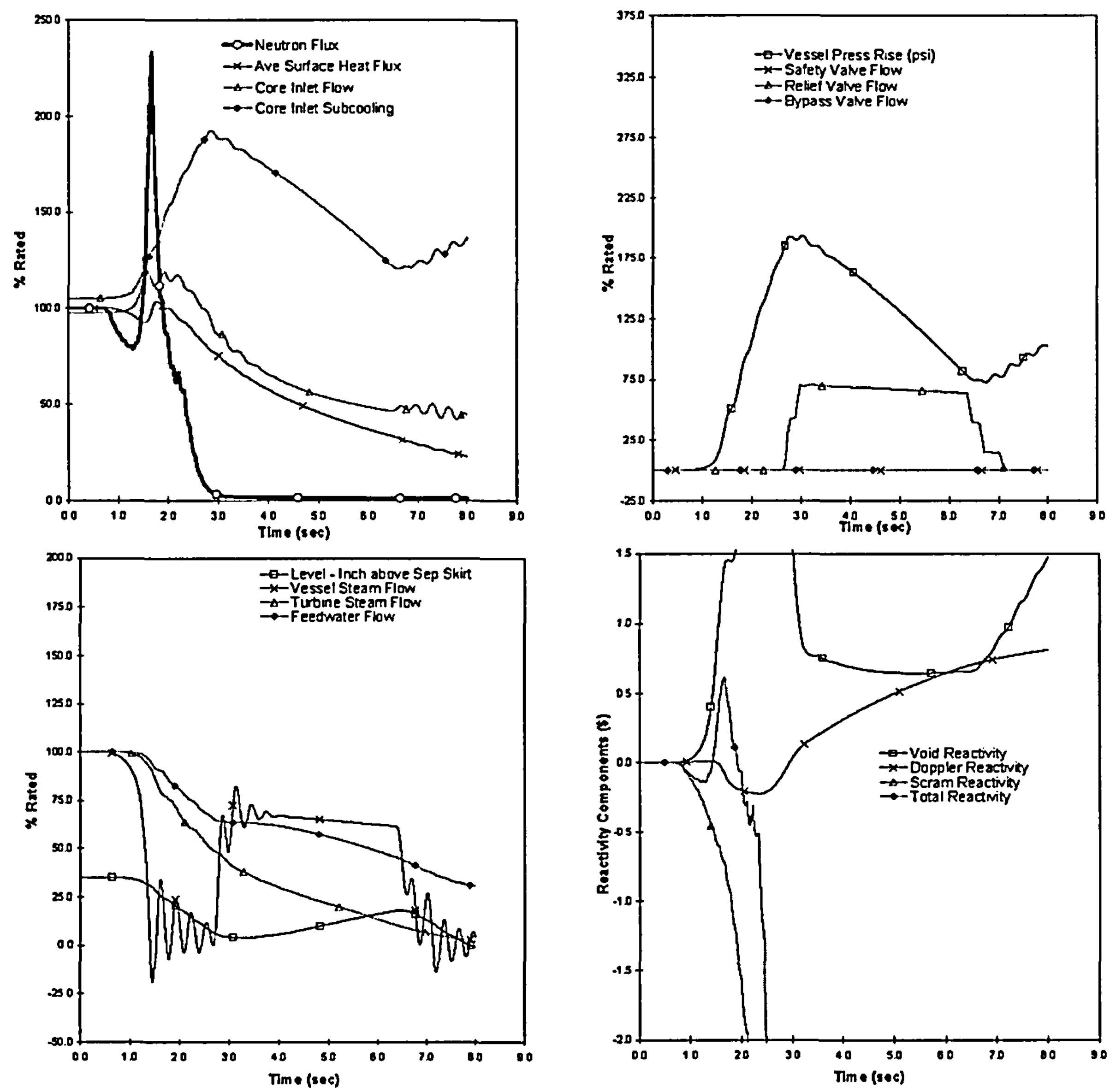
Figure 3-3: Feedwater Controller Failure with RFWT



APPENDIX C

Figure 3-13 (MSIV Closure) from the EPU Transient Analysis

Figure 3-13: Main Steam Isolation Valve Closure - Direct Scram



APPENDIX D

<u>Figure 3-7 (Load Reject with Bypass) from the EPU Transient Analysis</u>

Figure 3-7: Load Rejection With Bypass