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DOCKETED  
USNRC

August 9, 2007

August 13, 2007 (12:15pm)

Office of the Secretary  
Attn: Rulemaking and Adjudications Staff  
Mail Stop: O-16C1  
U.S. Nuclear Regulatory Commission  
Washington, DC 20555-0001

OFFICE OF SECRETARY  
RULEMAKINGS AND  
ADJUDICATIONS STAFF

Docket No. 50-271-LR

To Whom It May Concern:

Enclosed please find, per your request today, a complete, redacted version of New England Coalition's July 16, 2007 filing, " Opposition to Entergy's Motion for Summary Disposition of NEC's Contention 4 (Flow-Accelerated Corrosion)." Please contact me if you need anything further.

Thank you,

*Michelle Cronin*  
Michelle Cronin

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July 16, 2007

Office of the Secretary  
Attn: Rulemaking and Adjudications Staff  
Mail Stop O-16C1  
U.S. Nuclear Regulatory Commission  
Washington, D.C. 20555-0001

Re: In the Matter of Entergy Nuclear Vermont Yankee, LLC and Entergy  
Nuclear Operations, Inc. (Vermont Yankee Nuclear Power Station),  
Docket No. 50-271-LR, ASLBP No. 06-849-03-LR  
**Filing Attaching and Discussing Proprietary Documents**

Dear Sir or Madam:

Please find enclosed for filing in the above-stated matter New England Coalition, Inc.'s Opposition to Entergy's Motion for Summary Disposition of NEC's Contention 4 (Flow-Accelerated Corrosion). The following two documents that Entergy has designated proprietary are included in this filing as attachments F and H to the Declaration of Ulrich Witte, and are discussed in the legal memorandum:

1. Recommendations for an Effective Flow-Accelerated Corrosion Program (NSAC-202L-R3); and
2. Letter to James Fitzpatrick from EPRI (February 28, 2000).

The first of these documents is an EPRI guidance document for flow-accelerated corrosion programs. The second is a letter to an Entergy staff person at the Vermont Yankee (VY) plant, stating EPRI's evaluation of the VY FAC program, and recommending certain changes to that program.


Pursuant to the Protective Order governing this proceeding, an unredacted version of this filing, including the two proprietary documents, will be served only on the Board, the NRC's Office of the Secretary, and Entergy's Counsel. A redacted version of this filing that does not include the proprietary documents will be served on all other parties.<sup>1</sup>

<sup>1</sup> Entergy's Counsel has informed NEC that no party representative, other than NEC's counsel and consultant, have signed the Nondisclosure Agreement.



Thank you for your attention to this matter.

Sincerely,

A handwritten signature in cursive script, appearing to read "Karen Tyler", with a long horizontal flourish extending to the right.

Karen Tyler  
SHEMS DUNKIEL KASSEL & SAUNDERS PLLC

Cc: attached service list

**UNITED STATES OF AMERICA  
NUCLEAR REGULATORY COMMISSION**

Before the Atomic Safety and Licensing Board

In the Matter of )

Entergy Nuclear Vermont Yankee, LLC )  
and Entergy Nuclear Operations, Inc. )

(Vermont Yankee Nuclear Power Station) )

) Docket No. 50-271-LR

) ASLBP No. 06-849-03-LR

CERTIFICATE OF SERVICE

I, Michelle Cronin, hereby certify that copies of the NEW ENGLAND COALITION, INC.'S OPPOSITION TO ENTERGY'S MOTION FOR SUMMARY DISPOSITION OF NEC'S CONTENTION 4 (FLOW-ACCELERATED CORROSION), in the above-captioned proceeding were served on the persons listed below, by U.S. Mail, first class, postage prepaid; by Fed Ex overnight to Judge Elleman; and, where indicated by an e-mail address below, by electronic mail, on the 16th day of July, 2007.

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UNITED STATES  
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
Entergy Nuclear Vermont Yankee, LLC	)	Docket No. 50-271-LR
and Entergy Nuclear Operations, Inc.	)	ASLB No. 06-849-03-LR
	)	
(Vermont Yankee Nuclear Power Station)	)	

**NEW ENGLAND COALITION, INC.'S (NEC) OPPOSITION  
TO ENTERGY'S MOTION FOR SUMMARY DISPOSITION OF NEC'S  
CONTENTION 4 (FLOW-ACCELERATED CORROSION)**

Pursuant to 10 C.F.R. § 2.1205(b), New England Coalition, Inc. (NEC) opposes Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc.'s (Entergy) Motion for Summary Disposition of NEC's Contention 4 (Flow Accelerated Corrosion). Summary judgment is inappropriate because Entergy's motion serves only to define a genuine dispute of expert opinion concerning facts material to NEC's Contention 4 that must be resolved on hearing before the Atomic Safety and Licensing Board ("the Board"). NEC's opposition is supported by NEC's attached Statement of Disputed Material Facts and Response to Entergy's Statement of Material Facts Regarding NEC Contention 4 On Which no Genuine Dispute Exists, the Fifth Declaration of Dr. Joram Hopenfild (Exhibit 1) and attachments thereto, and the Declaration of Ulrich Witte (Exhibit 2) and attachments thereto.

**I. INTRODUCTION**

The Board defined the scope of NEC's Contention 4 as follows:

NEC Contention 4 alleges that Entergy's plan for managing flow-accelerated corrosion (FAC) in plant piping fails to meet the requirements of 10 C.F.R. § 54.21(a)(3), ie, "fails to demonstrate that the effects of

aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operations.”

Memorandum and Order (Ruling on Standing, Contentions, Hearing Procedures, State Statutory Claim, and Contention Adoption), LBP-06-20, 64 NRC 131, 192 (2006). As one basis supporting NEC Contention 4, NEC’s Petition to Intervene included the expert testimony of Dr. Joram Hopenfled that Entergy cannot successfully use the CHECWORKS model as part of its FAC program during the renewed license term because it will not be possible to properly calibrate CHECWORKS to EPU operating conditions before expiration of the current VYNPS license. *See*, Declaration of Dr. Joram Hopenfled (“Hopenfled Declaration I”) at ¶¶ 22-27.

The “undisputed facts” that purportedly support Entergy’s Motion for Summary Disposition of NEC’s Contention 4 are not facts for the most part, but rather the opinions of Entergy’s witnesses, Jeffrey S. Horowitz and James C. Fitzpatrick. These opinions can be summarized as follows: (1) the VYNPS FAC program now in effect under Entergy’s current operating license appropriately implements industry guidance and will serve as an adequate aging management plan with respect to FAC under the proposed renewed license; (2) a prolonged period of data collection is not required to benchmark CHECWORKS for post-EPU use at VYNPS because the model incorporates FAC data from many plants, and was designed to handle large changes in operating conditions produced by a power uprate; and (3) inspection data collected during the three post-EPU refueling outages scheduled under the current VYNPS license will be sufficient to benchmark the model to post-EPU VYNPS conditions. *See*, Joint Declaration of Jeffrey S. Horowitz and James C. Fitzpatrick In Support of Entergy’s Motion for Summary

Disposition of NEC Contention 4 (“Horowitz and Fitzpatrick Declaration”) at ¶¶ 25-32, 38-39. Entergy also newly represents that its aging management program addressing FAC during the license renewal period will be identical to the FAC program now in effect at VYNPS under its current license. Horowitz and Fitzpatrick Declaration at ¶ 25.

NEC witnesses Joram Hopenfled and Ulrich Witte disagree on substantial and technically credible grounds with the opinions of Mr. Horowitz and Mr. Fitzpatrick. *See*, Fifth Declaration of Dr. Joram Hopenfled (“Hopenfled Declaration 5”); Declaration of Ulrich Witte (“Witte Declaration”). A hearing before the Atomic Safety and Licensing Board (“the Board”) is necessary to resolve this dispute of expert opinion with respect to the following issues at a minimum:

- (1) Whether data collected under the current VYNPS FAC program during three post-EPU refueling outages scheduled prior to the expiration of the current VYNPS license will be sufficient to benchmark CHECWORKS to VYNPS post-EPU conditions; and
- (2) Whether the current VYNPS FAC program appropriately implements industry guidance, and will constitute an adequate aging management plan with respect to FAC.

## II. ARGUMENT

### A. STANDARD OF REVIEW

Motions for summary disposition before the NRC under 10 C.F.R. §§ 2.1205(c) and 2.710(d)(2) are analogous to motions for summary judgment before the federal courts and, accordingly, are evaluated pursuant to the standards governing summary judgment under Rule 56 of the Federal Rules of Civil Procedure. *See, Advanced Med. Sys., Inc. (One Factor Row, Geneva, Ohio)*, CLI-93-22, 38 NRC 98, 102 (1993). Under Rule 56, the movant is required to show the “absence of a genuine issue of material fact,” and

entitlement to judgment as a matter of law. *Celotex Corp. v. Caltrett*, 477 U.S. 317, 323, 325 (1986). In determining whether there are genuine issues of material fact, a court must consider all evidence in the light most favorable to the non-moving party. *Hunter v. Bryant*, 502 U.S. 224, 233 (1991).

Summary judgment is not appropriate if it would require a judge to engage in “credibility determinations, the weighing of evidence, [or] the drawing of inferences from the facts.” *Anderson v. Liberty Lobby*, 477 U.S. 242, 255 (1986). The need for such determinations signals the existence of a genuine factual issue that must be resolved based on evidence presented at a hearing, not on summary judgment. Summary judgment likewise is not appropriate if it would require a judge to assess the correctness of facts and conclusions stated in competing expert testimony. One Atomic Safety and Licensing Board explained this rule as follows:

[Summary disposition] is not a tool to convince a Licensing Board to decide, on written submissions, genuine issues of material fact that warrant resolution at a hearing.

\* \* \*

[E]ven a cursory review of the analogous federal case law governing summary judgment under the Federal Rules of Civil Procedure demonstrates that, when presented with conflicting expert opinion, trial courts are reticent to grant summary judgment. . . . [T]he weighing of the expert conclusions should be left to a trial, where the trier of fact will have the benefit of cross-examination to assist its evaluation.

The force of the above holdings applies to NRC licensing boards even though . . . we have a dual role, ruling on summary disposition motions and then ourselves becoming the trier of fact. But this does not mean we should – or readily could – combine both functions in one step whenever one party or another seeks to have us rule summarily. For, as has been seen, underlying the courts’ reluctance to act summarily in the face of competing expert testimony is the notion that the trial process itself . . . can go a long way toward illuminating the disputes and the strengths and weaknesses of the competing experts’ opinions. . . [I]n our hearings,

questioning . . . by the Board can likewise prove to be decisive in enabling us to render a sound decision.

*Private Fuel Storage, LLC (Independent Spent Fuel Storage Installation)*, LBP-01-39, 54 NRC 497, 509-510 (2001) (internal citations omitted); *See also, Schering Corp. v. Geneva Pharm.*, 339 F.3d 1373, 1377 (Fed. Cir. 2003) (resolution of disputed fact requiring expert opinion is improper on summary judgment); *Scharf v. U.S. Atty Gen.*, 579 F.2d 1240, 1243 (9<sup>th</sup> Cir. 1979) (“The affidavit in support of this theory was hardly convincing, but it required the court to resolve an issue of fact based on conflicting expert testimony. This is not the court’s function on summary judgment.”).

**B. MATERIAL FACTS ARE IN GENUINE DISPUTE.**

1. There is a genuine dispute of fact concerning whether data collected under the current VYNPS FAC program during three post-EPU refueling outages scheduled prior to the expiration of the current VYNPS license will be sufficient to benchmark CHECWORKS to VYNPS post-EPU conditions.

Entergy’s experts and NEC’s experts agree that the CHECWORKS model must be benchmarked to post-EPU VYNPS operating conditions. They disagree regarding how many years of inspection data are needed. Entergy’s experts contend that data Entergy collects during three refueling outages scheduled prior to the expiration of the current VYNPS license will suffice. *See*, Horowitz and Fitzpatrick Declaration at ¶ 39 (“Based on my experience with the use of CHECWORKS, [inspection data for three refueling outages under EPU conditions] are sufficient to calibrate the CHECWORKS predictions to provide a good fit to the VY post-EPU conditions.”). NEC’s experts, in contrast, contend that 7-15 years of data are necessary. *See*, Hopenfeld Declaration 5 at ¶¶ 6-7, 9-13, 15-19; Witte Declaration at ¶¶ 41-44.



Entergy's experts offer little support for their position that inspection data from three refueling outages is enough to calibrate CHECWORKS. Mr. Horowitz notes that the model incorporates FAC data from many plants. Horowitz and Fitzpatrick Declaration at ¶ 38. He also asserts, without elaboration or citation to industry experience, that the model "has been shown to handle large changes in chemistry, flow rate and or other operating conditions typically found in power uprates." *Id.* Finally, Mr. Horowitz offers his opinion that prolonged benchmarking "will not result in identifying new locations to inspect, but will in most cases determine that inspections at certain locations are not necessary." *Id.* Mr. Fitzpatrick claims that the piping system locations at VYNPS that are most susceptible to FAC are already "generally known," as they have been identified under the current VYNPS FAC program. *Id.* at ¶ 30.

NEC's experts dispute Mr. Horowitz's and Mr. Fitzpatrick's opinions on each of these points on credible technical grounds. Mr. Witte cites industry guidance supporting 5-10 years of data trending, and notes that trending to the high end of this range is appropriate where variables affecting wear rate have significantly changed. Witte Declaration at ¶ 41. Mr Witte is skeptical that CHECWORKS incorporates FAC data from plants that can be reasonably compared to VYNPS. He notes that only six operating plants have increased operating power by more than fifteen percent (15%), and that half of these have experienced problems with FAC. Witte Declaration at ¶ 43; *See also*, Hopenfeld Declaration 5 at ¶ 16. Mr Horowitz cites no industry experience in support of his claim that CHECWORKS has "been shown" to handle large changes in operating conditions. Both Mr. Witte and Dr. Hopenfeld, on the other hand, reference numerous FAC incidents at other facilities, including a number following power uprates. *See*,

Hopenfeld Declaration 5 at ¶¶ 6-7; Witte Declaration at ¶¶ 13-15, 43. It is Dr.

Hopenfeld's opinion that "the failure of the code to predict events at several of these plants can reasonably be attributed to the difficulty of obtaining sufficient data to establish reliable FAC trends." Hopenfeld Declaration 5 at ¶ 7. Dr. Hopenfeld disagrees that benchmarking CHECWORKS with data from more than three inspections will result in a reduction in the number of inspection locations. On the contrary, he believes that "because of the increase in the velocity and change in chemistry following EPU, new locations of high corrosion rates would be expected to set in without the ability of CHECWORKS to predict those locations." Hopenfeld Declaration 5 at ¶ 13.

Finally, both Dr. Hopenfeld and Mr. Witte deny that it would be sufficient to "generally know"<sup>1</sup> the piping system locations most susceptible to FAC, or that Entergy's current FAC program has in fact accurately produced this information. *See*, Hopenfeld Declaration at ¶¶ 15, 20-22; Witte Declaration at ¶¶ 6-12, 26-40. Both Mr. Witte and Dr. Hopenfeld take issue with the sufficiency of Entergy's current FAC program, and consequently with the validity of data produced under this program. Dr. Hopenfeld disputes fundamental engineering assumptions apparently underlying Entergy's current FAC program with respect to the relationship of wear to velocity, and the most susceptible geometries. Hopenfeld Declaration 5 at ¶¶ 12, 20-22. Mr. Witte concludes that "trending under this program is of marginal value." Witte Declaration at ¶ 42.

Mr. Witte disagrees that post-EPU inspection data collected under Entergy's current FAC program during three outages will suffice to calibrate CHECWORKS in part because he finds the program deficient. *Id.* at ¶ 44 ("It is also my opinion that

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<sup>1</sup> Indeed, the assertion that susceptible locations are "generally known" inherently suggests that some locations may not have been identified -- herein lies the problem.

[benchmarking CHECWORKS] can only be accomplished after the current program deficiencies are corrected and a proper baseline is established.”). Based on his detailed review of the records Entergy has produced to NEC in this proceeding, including the Applicant’s own assessments, audits, condition and cornerstone reports, and focused self assessments, Mr. Witte concludes that the VYNPS FAC program was in noncompliance with both the plant’s current licensing basis and EPRI guidance from about 1999 through at least 2006, and that a proper pre-EPU baseline may not have been established. Witte Declaration at ¶ 6-12, 26-40. Mr. Witte’s findings include, but are not limited to, the following:

- [REDACTED] from 1999-2006, Entergy apparently failed to update the CHECWORKS model in use at VYNPS with plant inspection data or information concerning plant modifications. This lengthy lapse may have significantly weakened the trending and predictive capability of the software, both during the lapse period and presently. *Id.* at ¶¶ 26-28.

- [REDACTED]

a [REDACTED]

- In 2005, the CHECWORKS model predicted wall thinning close to or exceeding acceptable code limits at several locations, but Entergy apparently produced no Condition Reports addressing these imminent potential pipe ruptures, or at least has not produced such reports to NEC in this proceeding. *Id.* at ¶ 30.

- Numerous internal Entergy reports label the VYNPS FAC program unsatisfactory. The program was deemed unsatisfactory in the 2004, and the 2006

cornerstone report expressed concern about the program and specifically the continued slow progress in updating the CHECWORKS model. *Id.* at ¶¶ 31, 32.

- A FAC-related pipe rupture appears to have occurred during the third quarter of 2006. *Id.* at ¶ 37.

- The 2006 refueling outage FAC inspection scope, planning, documentation and procedural analysis all appear to have been performed under a superseded program document, potentially invalidating the pre-EPU baseline for use of CHECWORKS. *Id.* at ¶ 39.

- Entergy apparently reduced the number of FAC inspection data points by fifty percent (50%) between the 2005 refueling outage and the 2006 refueling outage, in violation of its commitment to *increase* inspection data points by fifty percent (50%). *Id.* at ¶ 30.

Pursuant to the authority cited in Part II(A), above, the Board should not decide the amount of time necessary to benchmark CHECWORKS to post-EPU conditions at VYNPS based on conflicting expert declarations. Nor should it resolve underlying issues of witness credibility and weight of evidence on summary judgment. This issue should be resolved following a hearing before the Board that will provide the opportunity for full exploration of the issues through live testimony and questioning by the Board.

2. There is a genuine dispute of fact concerning whether the current VYNPS FAC program appropriately implements industry guidance, and will constitute an adequate aging management plan with respect to FAC during the license renewal period.

Both Mr. Horowitz and Mr. Fitzpatrick contend that the current VYNPS program appropriately implements industry guidance and will constitute an adequate aging management plan with respect to FAC during the license renewal period. *See*, Horowitz

and Fitzpatrick Declaration at ¶¶ 26-30, 32. Mr. Horowitz draws this conclusion following a two-day audit, during which time he reviewed a number of documents that Entergy has unaccountably chosen not to file with the Board, and interviewed certain Entergy staff. *See, Id.*, Attachment 3 ("Summary of Observations During VY Site Visit").

As stated in Part II(B)(1), NEC's expert witnesses disagree with this assessment, contesting engineering assumptions underlying Entergy's current FAC program, as well as its recent compliance with industry guidance and general validity. Hopensfeld Declaration 5 at ¶¶ 12, 20-22; Witte Declaration at ¶¶ 6-12, 26-40. This issue should not be resolved on summary disposition, but rather based on a hearing before the Board, where the conflicting opinions of Entergy's and NEC's experts can be fully explored through questioning of witnesses.

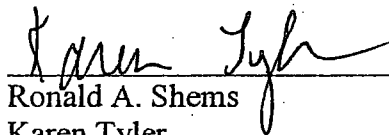
### III. CONCLUSION

Entergy's Motion for Summary Disposition of NEC's Contention 4 (Flow-Accelerated Corrosion) should be denied.

July 15, 2007

New England Coalition, Inc.

by:



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Karen Tyler

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For the firm

Attorneys for NEC

UNITED STATES  
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
Entergy Nuclear Vermont Yankee, LLC	)	Docket No. 50-271-LR
and Entergy Nuclear Operations, Inc.	)	ASLB No. 06-849-03-LR
	)	
(Vermont Yankee Nuclear Power Station)	)	

**NEW ENGLAND COALITION'S STATEMENT OF DISPUTED MATERIAL  
FACTS AND RESPONSE TO ENTERGY'S STATEMENT OF MATERIAL  
FACTS REGARDING NEC CONTENTION 4 ON WHICH NO GENUINE  
DISPUTE EXISTS**

*Note: Entergy's Alleged Undisputed Material Facts are reproduced below, followed by NEC's response.*

A. THE FAC PROGRAM AT VY

1. Section B.1.13 of the License Renewal Application for VY ("Application") indicates that the VY program for addressing flow accelerated corrosion ("FAC") of steel piping and components is comparable to the program described in the NRC guidance document "Generic Aging Lessons Learned (GALL) Report – Tabulation of Results," NUREG-1801, Vol. 2, Rev. 1 (Sep. 2005) ("NUREG-1801"), Section XI.M17, Flow Accelerated Corrosion.

**NEC Response:** Agreed that this is the language of the License Renewal Application. Denied that the VYNPS FAC program is actually implemented in accordance with NRC and industry guidance. Declaration of Ulrich Witte ("Witte Declaration") at ¶¶ 6-12, 24-40.

2. The scope of an implementation guidelines for the FAC Program at VY during the license renewal period are described in the Electric Power Research Institute ("EPRI") guidance document NSAC-202L.

**NEC Response:** Agreed that these guidelines apply. Denied that the VYNPS program is actually implemented in accordance with EPRI Guidance. *Id.*

3. A program implemented in accordance with the EPRI guidelines predicts, detects, and monitors FAC in plant piping and other components, such as elbows and expanders. Such a program includes the following recommendations: (a) conducting an analysis to determine critical locations; (b) performing limited baseline inspections to

determine the extent of thinning at these locations; and (c) performing follow-up inspections to confirm the predictions, or repairing or replacing components as necessary. To ensure that all aging effects caused by FAC are properly managed, the program includes the use of a predictive code, such as CHECWORKS, that uses the implementation guidance of NSAC-202L to satisfy the criteria specified in 10 CFR Part 50, Appendix B, criteria for development of procedures and control of special processes.

**NEC Response:** Agreed that general EPRI recommendations are accurately referenced. Denied that use of the CHECWORKS model during the license renewal period at VYNPS will ensure that aging effects caused by FAC are properly managed in compliance with NRC regulations. Fifth Declaration of Dr. Joram Hopenfled (Hopenfled Declaration 5) at ¶¶ 6-23; Witte Declaration at ¶¶ 24-40, 41-44.

4. A FAC Program based on the EPRI guidelines, including the most recent revision of NSAC-202L, has been in effect at VY since 1990. The VY FAC Program including appropriate procedures or administrative controls to assure that the structural integrity of all carbon steel lines containing high-energy fluids (two phase as well as single phase) is maintained.

**NEC Response:** Entergy's Alleged Undisputed Fact #4 is a statement of opinion, not fact. Denied that the VY FAC Program has been consistent with EPRI guidelines, or will be adequate to ensure structural integrity of plant piping during the license renewal period. Witte Declaration; Hopenfled Declaration 5.

5. The criteria for component selection for FAC inspection during outages at VY are consistent with those cited in NSAC-202L, with the selection being based on (1) pipe wall thickness measurements from past outages, (2) predictive evaluations performed using the CHECWORKS code, (3) industry events related to FAC, (4) results from other plant inspection programs, and (5) engineering judgment. Other factors considered in planning inspections at VY include the consequences of failure of a particular component with respect to personnel safety and plant availability, and the margin of nominal wall thickness to code minimum wall thickness.

**NEC Response:** Denied. Entergy's Alleged Undisputed Fact #5 states a judgment, not a fact. Denied that the VY FAC Program is consistent with EPRI guidance. Witte Declaration ¶¶ 6-12, 24-40. Criteria for component selection during outages and the scope of inspection in the VY FAC Program are inadequate because they are based on questionable predictions and questionable engineering judgment at VY regarding FAC. *Id.*; Hopenfled Declaration 5.

6. The VY FAC Program provides detailed instructions on how to conduct the inspections, the evaluation of the inspection data, acceptance criteria for inspected components, disposition of components failing to meet acceptance criteria, expansion of

the sample to other components similar to those failing to meet acceptance criteria, and updating CHECWORKS models to incorporate inspection data.

**NEC Response: Denied. “Detailed” is ambiguous and subject to varying interpretations by different experts. No conclusion can be reasonably drawn or legitimately inferred from the statements in #6. Denied that the CHECWORKS model used in the VY FAC Program was consistently updated to incorporate inspection data. Witte Declaration ¶¶ 26-27.**

7. The FAC Program currently in effect at VY will continue to be implemented during the license renewal period.

**NEC Response: Agreed only to the extent that Entergy makes this representation in its Motion for Summary Disposition.**

8. The FAC Program at VY is complemented by the use of FAC-resistant materials in the design of the plant, the use of a water chemistry that inhibits FAC, and the progressive replacement of FAC susceptible piping and components with FAC resistant ones.

**NEC Response: Agreed in part; denied in part. Entergy has not specified the extent to which FAC-resistant materials have replaced FAC-susceptible materials, and has not provided analyses of the performance of the FAC inhibiting water chemistry program. Therefore, no conclusion can be reasonably drawn or legitimately inferred from the statements in #8.**

9. The piping system locations at VY that are most susceptible to FAC are generally known, since they are typically the areas of high flow velocity and the regions of high turbulence. These locations have already been identified through many years of inspections performed under the FAC Program. These locations provide a baseline for the performance of inspections, which is refined by the use of the CHECWORKS code and other tools.

**NEC Response: Denied. The meaning of “generally known” is ambiguous and subject to varying interpretation by different experts. Denied that the VY FAC Program has been appropriately implemented so as to accurately identify FAC susceptible locations or establish a proper baseline. Witte Declaration at ¶¶ 6-12, 24-40; Hopenfled Declaration 5 at ¶¶ 20-22.**

10. A two-day audit of the Vermont Yankee FAC Program conducted in April 2007 by a recognized industry expert found that the program appropriately implements the approach recommended by NSAC-202L. The program was found to have substantial strengths and no apparent weaknesses. The observed program strengths include, in addition to conformance with NSAC-202L, the extensive use of FAC-resistant materials in the original construction, relatively simple plant design, proactive replacement of



vulnerable components with others of resistant material, and an experienced program lead.

**NEC Response:** Agreed that Entergy has filed a memorandum from its expert stating these opinions in very general terms. Denied that Entergy's VY FAC Program is without weaknesses or appropriately implements EPRI guidance. Witte Declaration at ¶¶ 6-12, 24-40; Hopenfeld Declaration 5 at ¶¶ 20-22.

11. The auditor concluded that the VY FAC Program has been effective at managing aging effects, and that the program provides reasonable assurance that the effects of aging will be managed such the applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. This conclusion was consistent with other favorable audits of the program by the NRC, Entergy and EPRI.

**NEC Response:** Agreed that Entergy has filed a memorandum from its expert stating these opinions in very general terms. Denied that Entergy's current VY FAC Program will be an effective aging management tool. Witte Declaration; Hopenfeld Declaration 5.

#### B. USE OF CHECWORKS

12. The CHECWORKS code is one of the tools used at VY to identify FAC-susceptible areas. It is used in conjunction with trend data from actual inspections, operating experience and engineering judgment, among other information, in deciding where to conduct piping inspections.

**NEC Response:** Agreed.

13. The changes that have been made in piping and component materials, the higher flow velocities due to EPU operations, and the adjustments in water chemistry have all been incorporated into the CHECWORKS model that is used at VY.

**NEC Response:** Denied that CHECWORKS has been benchmarked to VY at EPU, or can be benchmarked to VY at EPU before the expiration of the current VY operating license. Three outage data sets (unquantified and unqualified) are not sufficient to calibrate CHECWORKS for license extension. Hopenfeld Declaration 5; Witte Declaration.

14. In the three refueling outages that are scheduled to occur between implementation of the EPU at VY in 2006 and the end of the current license in 2012, the number of piping inspections will be increased by 50 percent. Therefore, by the time the license renewal is in effect (in the year 2012), three refueling outages (4.5 years) of

inspection data under EPU conditions will have been obtained and added to the CHECWORKS database and wear rate predictions.

**NEC Response:** Agreed that Entergy has made this representation. Denied that inspection data points have increased, given that there were apparently 50% fewer inspection data points during the 2006 refueling outage than during the 2005 refueling outage. Witte Declaration at ¶ 38.

15. A user of the CHECWORKS code constructs a mathematical model of the susceptible piping systems, similar in concept to a piping stress model or flow model. Plant design, water chemistry and operating data, together with a predictive algorithm, are used to predict the rate of wall thinning, and remaining service life on a component-by-component basis. The resulting predictions are then used by plant personnel to help select inspection locations. The CHECWORKS predictions are refined by comparing inspection data with the CHECWORKS predictions. This approach provides a more accurate prediction of the wear rates than trending alone and allows the analyst to gauge the success of the program in predicting piping wear by comparing the analytical predictions with the actual observed wear.

**NEC Response:** Agreed to the extent of the general description of CHECWORKS and its intended use. Denied that CHECWORKS can be benchmarked for effective post-EPU use at VY before expiration of Entergy's current operating license. Hopenfled Declaration 5; Witte Declaration.

16. As a result of the use of the CHEC and its successor programs including CHECWORKS and the associated development of technology and programmatic guidance on FAC control, there has never been a fatality at any plant using the CHEC or its successors since the first release of CHEC in 1987.

**NEC Response:** Denied. Entergy's Alleged Undisputed Fact #16 is in part a statement of opinion, not fact, and seeks to establish cause and effect by an unsupported correlation. Hopenfled Declaration 5 at ¶ 8. Entergy has not identified the data supporting the remainder of this statement.

17. There has not been a major FAC-caused pipe rupture in a nuclear unit in the United States for more than 7 years. This is compared to approximately one major rupture a year at plants in countries where CHECWORKS is not used.

**NEC Response:** Entergy has not identified the data supporting this statement. No legitimate inference may be drawn regarding CHECWORKS performance from either #16 or #17. Hopenfled Declaration 5 at ¶ 8.

18. NEC alleges that CHECWORKS may not be used at VY during the initial years of license renewal operations because CHECWORKS must be continuously updated with plant-specific data so that, once "benchmarked" to a specific plant, it makes

accurate predictions as long as plant parameters, such as velocity and coolant chemistry, do not change drastically. Since those parameters have changed at VY as a result of the EPU, NEC alleges that it would take 10-15 years of inspection data collection and entry to the model following the power uprate to benchmark CHECWORKS for use at VY.

**NEC Response: Agreed that these are statements contained in NEC's Petition to Intervene and the Supporting Declaration of Dr. Joram Hopenfeld.**

19. No such prolonged period of data collection is required to use CHECWORKS effectively. The predictive algorithms built into CHECWORKS are based on all available laboratory data and FAC data from many plants. CHECWORKS was designed, and has been shown, to handle large changes in chemistry, flow rate and other operating conditions typically found in power uprates. Its predictions provide "best-estimates" of the FAC wear rates at particular plants, including VY. The plant-specific information this is obtained during the plant inspections is to be used to adjust the estimates to more realistic levels that reflect the plant's configuration, water chemistry and operating conditions. Prolonged "benchmarking" as suggested by Dr. Hopenfeld will not result in identifying new locations to inspect, but will in most cases determine that inspections at certain locations are not necessary.

**NEC Response: Denied. #19 is a statement of opinion/ subjective judgment, with which NEC's experts disagree. Hopenfeld Declaration 5; Witte Declaration ¶¶ 41-44.**

20. In addition, by the time the VY license renewal is in effect (in the year 2012), inspection data for three refueling outages under EPU conditions will have been obtained. These additional data sets, when added to the CHECWORKS database, will result in more refined wear rate predictions. These additional inspection data sets are sufficient to calibrate the CHECWORKS predictions to provide a good fit to the VY post-EPU conditions.

**NEC Response: Agreed that Entergy has represented that it will collect inspection data during three refueling outages under EPU conditions before its current VY license expires. The remainder of #20 is a statement of opinion/ subjective judgment, with which NEC's experts disagree. *Id.***

21. NEC also asserts that it may be necessary to modify the FAC Program as a plant ages and that Entergy's license renewal application does not explain how it proposes to use CHECWORKS as an aging management tool during the period of extended operation. However, CHECWORKS has the demonstrated ability to handle without problems the impact of changes of operating conditions in units, such as VY, that undergo chemistry changes or power uprates.

**NEC Response: Denied. Entergy's Alleged Undisputed Fact #21 is an unsupported and conclusory statement, with which NEC's experts disagree. *Id.***

22. EPRI periodically re-examines the success of the program in predicting piping and component wear rates and refines the model as necessary. The predictive model has been improved over the years as more plant experience and inspection data has become available, keeping the program an effective aging management tool.

**NEC Response: Agreed that EPRI may periodically reexamine and refine the model. The remainder of #22 is a statement of opinion/ subjective judgment, with which NEC's experts disagree. *Id.* Moreover, NEC notes that the Entergy VY FAC Program has not consistently used the most current version of the CHECWORKS model. Witte Declaration at ¶ 29.**

**EXHIBIT 1**

**UNITED STATES  
NUCLEAR REGULATORY COMMISSION**

In the Matter of	)	
	)	
ENTERGY NUCLEAR VERMONT YANKEE, LLC	)	Docket No. 50-271-LR
and ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLB No. 06-849-03-LR
	)	
Vermont Yankee Nuclear Power Station	)	

**FIFTH DECLARATION OF DR. JORAM HOPENFELD**

1. My name is Dr. Joram Hopenfeld. New England Coalition, Inc. (NEC) has retained me as an expert witness in proceedings concerning the application of Entergy Nuclear Operations, Inc. ("Entergy") to renew its operating license for Vermont Yankee Nuclear Power Station ("VYNPS") for twenty years beyond the current expiration date of March 21, 2012.
2. I am a mechanical engineer and hold a doctorate in mechanical engineering. My curriculum vitae was attached to my first declaration in support of NEC's Petition to Intervene, filed May 26, 2006.
3. I submit the following comments in support of NEW ENGLAND COALITION'S ANSWER OPPOSING ENTERGY'S MOTION FOR SUMMARY DISPOSITION OF NEC CONTENTION 4 (FLOW-ACCELERATED CORROSION).
4. Entergy's Motion for Summary Disposition, together with its attendant declarations, contains numerous false conclusions based on faulty assumptions and apparent misunderstandings regarding the physical phenomena associated with flow

accelerated corrosion (FAC). A discussion of selected technically based assertions in Entergy's filing, sufficient to establish that Entergy's arguments and testimony are by no means dispositive and that technically credible and substantial dispute of the facts remains follows below:

#### **Contention 4: Management of Flow-Accelerated Corrosion**

5. The license renewal application is reviewed in accordance with NUREG 1800 and NUREG 1801. NUREG 1801 XI.M17 states that the FAC program:

Relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R2 for an effective flow-accelerated corrosion (FAC) program. The program includes performing (a) an analysis to determine critical locations, (b) limited baseline inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm the predictions, or repairing or replacing components as necessary.

Entergy has not proposed a valid program to determine critical locations and inspection frequencies during the full proposed period of extended operation.

6. Entergy again takes exception to my professional opinion that it takes 10-15 years of accumulated data before CHECWORKS can be used reliably. NEC's Petition to Intervene provides a number of references demonstrating that costly and catastrophic accidents caused by FAC have occurred in the last 15 years. The facts are that unpredicted failures associated with FAC continue to occur. During the past three years alone, unanticipated pipe thinning or failure events have occurred at numerous U.S. nuclear plants. The fact that in many of these events the pipe actually leaked demonstrates that CHECWORKS requires much more calibration at each plant than is currently realized. Since CHECWORKS prediction rates are based on historical global thinning rates, the occurrence of so many unanticipated leaks strongly suggests that either the thinning rate is not linear with time or it is highly local, making it very difficult to

enter the correct information into CHECWORKS. Recent failures occurred at the following plants: Duane Arnold, Hope Creek, Clinton, Braidwood, LaSalle, Peach Bottom, Palo Verde, Palisades, Catawba, Calvert Cliffs, Browns Ferry, and Kewaunee. *See*, Attachment A, "VY Piping FAC Inspection Program PP 7028 – 2007 Refueling Outage" at 7-11; Attachment B, "Kewaunee 3Q/2006 Plant Inspection Findings" at 4. Very recent piping events are currently being investigated for failure mechanisms at Cooper, SONGS, and Nine Mile point. *See*, Attachment C, Union of Concerned Scientists Issue Brief, "Control Rod Problem at Cooper"; Attachment D, NRC Event Notification Report (June 21, 2007); Attachment E, "Nine Mile Point Nuclear Station – NRC Special Inspection Report 50-220/03-003 – Preliminary White Findings (April 15, 2003). Some of these plants have received power uprate approvals, and are operating at increased power levels. *See*, Attachment F, NRC Fact Sheet on Power Uprates for Nuclear Plants; Attachment G, Union of Concerned Scientists Fact Sheet on Power Uprate History.

7. The FAC experience in those plants that have received EPU licenses, specifically their failure rates after baselining the configuration geometries and wear rates post-EPU, is of particular interest. Plants with post-EPU FAC-related failures include: Clinton, Palo Verde, and Kewaunee. *See*, Attachments A, B, F, G. Since CHECWORKS is not a mechanistic model, it is my professional opinion that the failure of the code to predict events at several of these plants can reasonably be attributed to the difficulty of obtaining sufficient data over a sufficiently long period of time to establish reliable FAC trends.

8. In ENTERGY'S MOTION FOR SUMMARY DISPOSITION, Entergy stated that "there has never been a fatality at any plant using CHEC or its successors, including

CHECWORKS, since the first release of CHEC in 1987.” This statement raises three concerns:

- Apparently Entergy has adopted the position that if a low-probability event has not happened in the past it will not happen in the future.
- While the narrow wording of the above statement is correct, in the broader sense the statement is misleading. As I pointed out to the Board in my Declaration of June 14, 2006, several workers were killed at the Mihama nuclear power plant due to FAC in the secondary loop in July 2004. I do not know whether the Mihama plant used CHECWORKS, or one of its predecessors, but I believe that, like other nuclear plants, Mihama used some kind of computer code or database based, like CHECWORKS, on global wear rates rather than local wear rates. I do not agree with Entergy’s implication that the use of CHECWORKS assures plant and public safety.
- This statement suggests that Entergy is overconfident in CHECWORKS, and that excessive reliance on the model may become the rationale for reducing the frequency of a yet to be provided inspection program. This would not be in the interest of public safety.

9. I disagree with Entergy that inspection data from three post-EPU refueling outages scheduled prior to the expiration of the current VYNPS license will be sufficient to benchmark CHECWORKS.

10. I continue to maintain that CHECWORKS is not a mechanistic model, and therefore it requires considerable benchmarking to be used as a reliable predictive tool.



The reason that considerable effort is required to benchmark the code stems from the fact that many complex physical processes control the FAC phenomena. CHECWORKS can at best provide a gross relative ranking of various components with regard to their susceptibility to FAC. I would encourage Entergy to continue to compare data with predictions. However, the code should not be used as a predictive tool and a substitute for detailed inspections unless the measurement data covers a large number of components and carefully selected inspection sites and has been collected for at least 10-15 years.

11. FAC predictions can be made in laboratory environments on simple geometries (e.g., rotating discs). In real plants, where many variables may be interacting, the problem is much more complex. In refineries and off-shore facilities, for example, operators typically do not rely on models, but instead inspect thoroughly and replace material as required. Many years of accumulated experience and instrumentation are necessary to identify the areas in the plant that require frequent inspections. Entergy has no basis for stating that data from three inspections is sufficient to benchmark the code. Reactor plant experience, some of which I detailed below, indicates that 10-15 years is a more reasonable time to establish trends in the plant. Of course, if only a limited number of the susceptible components are inspected during that period, the code will be then restricted only to those components that were inspected. Entergy has indicated that it will increase the number of inspections by 50%, but has not disclosed what this physically means in terms of the total percentage of component and piping surface area susceptible to FAC that will be covered during the three outages.

12. Entergy is misled in believing that incorporating the higher EPU velocities in CHECWORKS has any significance. Wall thinning is affected by turbulence and not

velocity alone; velocity is important only as far as it affects turbulence. The EPU calculated velocity is an average velocity and not the local velocity, which more closely affects turbulence. CHECWORKS does not have the necessary database to account for local turbulence as it changes with time in various components at VY.

13. Contrary to the assertions of Entergy and its witnesses, I maintain that because of the increase in the velocity following EPU and a change in water chemistry in 2003, new locations of high corrosion rates would be expected to set in without the ability of CHECWORKS to predict those locations.

14. FAC increases as the plant ages. It is possible that Entergy's auditor was given some new information that would allow him to predict that the VYNPS program would assure adequate FAC management taking into consideration aging phenomena. NEC has not seen any information to indicate that this is the case.

15. I do not agree with Mr. James C. Fitzpatrick's statement that it is sufficient that "the piping system locations at VY that are most susceptible to FAC are generally known, since they are typically the areas of high flow velocity and the regions of high turbulence." As I have already stated above, one must know the exact spot on a given component where conditions are most favorable to FAC. The knowledge that one component is more susceptible to FAC than others is not sufficient. Two components of apparently the same materials subjected to almost the same velocities and same water chemistry may exhibit different FAC damage. One component may be severely damaged from FAC while the other would exhibit little or no damage.

16. I do not agree with Mr. Jeffrey S. Horowitz that because CHECWORKS incorporates data from many plants, a long period of data collection is not required to

benchmark the model. The flow velocity and water chemistry at VYNPS has been changed significantly and therefore a certain time would be required to benchmark the code. To some degree, this can be attributed to the fact that FAC inspection is largely done by sampling and the erosion rate may not be linear with time. Considering that major failures at plants like Surry and San Onofre have been detected only after 10 years of operations, 10-15 years is not a long time to benchmark CHECWORKS.

17. Mr. Horowitz's general statement that "CHECWORKS was designed, and has been shown, to handle large changes in chemistry, flow rate and or other operating conditions" is not an adequate technical support for his contention that data from three inspection cycles is sufficient to benchmark an empirical code like CHECKWORKS at VYNPS. Because CHECWORKS is based on data from many different plants, it is a ranking tool of components with respect to their susceptibility to FAC damage. Since FAC is highly local and probably not linear with time, the ability of CHECWORKS to predict failures based on historical data is highly uncertain, as evidenced by the failures discussed in 6 above and in my first declaration.

18. Mr. Horowitz cites his experience with CHECWORKS as sufficient to assure that three inspections at VYNPS at EPU conditions are adequate to benchmark CHECWORKS. Mr. Horowitz does not show or discuss how this empirical code accounts for conditions where the wear is not linear with time, and for the fact that the wall thickness of only a small fraction of the total surfaces susceptible to FAC will be actually measured during the next three inspections. Since the entire methodology of FAC inspection is based on sampling, one must assess CHECWORKS in terms of its ability to predict the probability of detecting wall thinning locations that would exceed

the minimum design thickness between inspection intervals. Mr. Horowitz has not done this, and therefore I consider his statements highly speculative.

19. The CHECWORKS code has not been, nor apparently will it be, benchmarked for sufficient duration under VYNPS EPU operating conditions (flow velocities, chemistry, materials, geometry), and therefore it cannot be used as a predictive model to define inspection scope and frequency during at least some portion of the proposed period of extended operation.

20. Entergy states that it does not rely only on CHECWORKS to define the scope and frequency of inspections, but does not describe other tools beyond saying that they are based on "other plant experience", "engineering judgment" and "operating experience." I note, however, that in addition to the above-discussed issues with Entergy's proposed use of CHECWORKS, Entergy's FAC program criteria for component selection during outages and the scope of inspection are inadequate because they are based on questionable engineering judgment regarding FAC.

21. Entergy does not now repudiate and therefore apparently continues to contend, as stated in its Answer to NEC's Petition to Intervene, that generally the increase in wear is less than the increase in velocity; and typically, from EPU studies, the maximum increase in projected wear rates is in proportion to the velocity increase. This proposition is entirely unsupported and demonstrates Entergy's apparent fundamental lack of understanding of FAC physical phenomena. At the November 2005 NRC ACRS EPU meeting in Brattleboro, Vermont, I questioned the validity of this very contention concerning velocity dependence, in the presence of Entergy staff, for the following reason: It is commonly accepted that mass transfer phenomena play an important part in

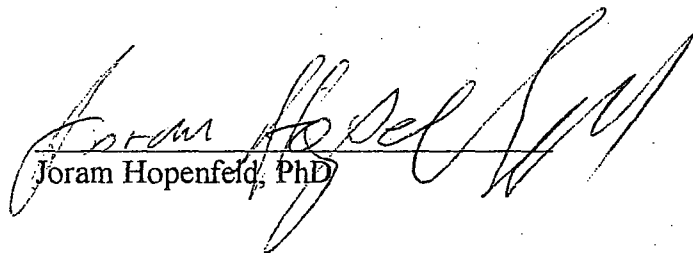
the mechanism of FAC. As such, the mass transfer coefficient would control FAC when the process is not controlled by chemical kinetics. At high turbulence, such as flow around bends and in pipe enlargements, the local mass transfer coefficient for a single phase flow is more likely to be proportional to the square of the velocity and not to the velocity itself. In the case of two phase flow, I expect the wall thinning rate to be proportional to the square of the velocity which is normal to the wall and not directly to the flow velocity as Entergy contends. Subsequently, the ACRS also challenged Entergy's contention regarding the low dependence of wear on velocity. Such dependence may be true only in straight, smooth pipe sections.

22. Finally, Entergy does not now repudiate and therefore apparently continues to represent, as stated in its Answer to NEC's Motion to Intervene at 35, that its FAC inspections during the outages prior to license extension will focus on "the highest length locations and the highest velocity locations." I continue to strongly disagree with Entergy that a focus on the highest velocity and the highest length locations would ensure sufficient data by 2012 to benchmark CHECWORKS. It is not clear at all how the highest length is related to FAC. As already mentioned above, the mass transfer coefficient is not only a function of velocity, but also of the geometry. I strongly recommend that Entergy review the failure from FAC of the Surrey pipe elbow, which reveals that Entergy's approach is oversimplified. Entergy contends that, in addition to using CHECWORKS, they will depend on "operating experience and engineering judgment". Entergy's discussion of FAC phenomena on Answer to NEC's Contention 4 does not demonstrate an understanding of FAC.

23. It remains my recommendation that unless VY can provide better assurances that the inspection program at VYNPS will be adequate to prevent wall thickness of pressure boundaries from falling below the ASME allowable thickness, VY should replace all FAC susceptible piping and components with FAC resistant components prior to extended license operation, in order to restore reasonable assurance of public health and safety. I further recommend that, before Entergy is granted a License Extension, the inspection program should be reviewed by at least two competent and qualified engineers for the purpose of insuring that Vermont Yankee is not operated beyond 2012 in an unanalyzed condition and at increased risk of component failure. Reviewing engineers should be completely independent from those who are responsible for the operation of the VYNPS and other parties to this litigation. The indicated inspection program must be of sufficient rigor and precision as to provide adequate assurance of public health and safety during the proposed period of extended operation.

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

Executed this 16 day of July, 2007 at Rockville, Maryland.

  
Joram Hopenfeld, PhD

## VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage

## Inspection Location Worksheets / Methods and Reasons for Component Selection

By: James C. FitzpatrickReviewed: Thomas M. O'Connor**FAC PROGRAM INSPECTION PLANNING:**

Piping components are selected for inspection during the Spring 2007 refueling outage (RFO26) are based on the following groupings and/or criteria.

Large Bore Piping

- LA: Components selected from measured or apparent wear found in previous inspection results.
- LB: Components ranked high for susceptibility from current CHECWORKS evaluation and /or identified as having the highest increases in flow velocities under EPU conditions.
- LC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.
- LD: Components selected to calibrate the CHECWORKS models.
- LE: Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. (through the Systems Engineering Group).
- LF: Engineering judgment / Other
- LG: Piping identified from EMPAC Work Orders (malfunctioning equipment, leaking valves, etc.)
- LH: Components "De-Scoped" (inspections deferred) from Previous Outages

Small Bore Piping

- SA: Susceptible piping locations (groups of components) contained in the Small Bore Piping data base which have not received an initial inspection.
- SB: Components selected from measured or apparent wear found in previous inspection results.
- SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.
- SD: Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. (through the Systems Engineering Group).
- SE: Engineering Judgment / Other.
- SG: Piping identified from EMPAC Work Orders (malfunctioning equipment, leaking valves, etc.)
- SH: Components "De-Scoped" (inspections deferred) from Previous Outages

Feedwater Heater Shells

No feedwater heater shell inspections will be performed during the 2007 RFO. All 10 of the feedwater heater shells have been replaced with FAC resistant materials.



**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LA: Large Bore Components selected (identified) from previous Inspection Results**

From the 1996 through 2005 Refueling Outage Inspection Reports, references (2) to (8): Large Bore Piping components were identified as requiring future monitoring. The following components have either yet to be inspected as recommended, or the recommended inspection is in a future outage.

Inspect. No.	Loc. SK.	Component ID	Notes /Comments / Conclusions
96-18 96-19	001	FD13EL05 FD13SP06	1996 Report: calculated time to Tmin is 11.5 & 12 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. <b>UT inspect elbow and downstream pipe in 2008</b>
96-36	002	FD02SP05	1996 Report: calculated time to Tmin is 9.5 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. <b>UT inspect elbow and downstream pipe in 2007</b>
96-37	005	FD07SP01	1996 Report: calculated time to Tmin is 9.6 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. DS elbow shows significant margin RSL= 47 cycles from 1996. EPU flow will increase velocity ~22%. <b>UT inspect upstream pipe FD07SP01DS, elbow FD07EL02, and downstream pipe FD07SP02US in 2007 (repeat the 1996 inspections)</b>
96-39	005	FD07SP02US	1996 Report: calculated time to Tmin is 10.5 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. <b>UT inspect upstream pipe FD07SP01DS, elbow FD07EL02, and downstream pipe FD07SP02US in 2007 (repeat the 1996 inspections)</b>
98-05 98-07	005	FD07EL06 FD07EL07	1998 Report: calculated time to Tmin is 7.5 & 6.7 cycles based on a single measurement. The 2007 RFO is 8 cycles since the inspection. Review of 1998 data for FD07EL06, FD07SP07, and FD07EL07 shows recommendations were made based on wear rates conservatively calculated from single low point measurements at weld counterbores. Significant margins exist on body of pipe and elbows. Defer this inspection to RFO 27 in 2008. At that time components will have ~1.7 cycles of operation under increased EPU flows. <b>UT inspect elbow FD07EL07 and downstream pipe FD07SP08 in 2008</b>
99-13	011	FD08EL04 FD08SP04	1999 Report: calculated time to Tmin is 7.9 & 12.5 cycles based on a single UT inspection. The 2007 RFO is 5 cycles since the inspection. Review of 1999 data for FD08EL04, & FD08SP04, shows recommendations were made based on wear rates conservatively calculated from single low point measurements at weld counterbores. Significant margins exist on body of pipe and elbows. Defer this inspection to RFO 27 in 2008. At that time components will have ~1.7 cycles of operation under increased EPU flows. <b>UT inspect elbow and downstream pipe in 2008</b>
99-16	011	FD08SP05	1999 Report: calculated time to Tmin is 6.1 cycles based on a single measurement. The 2007 RFO is 5 cycles since the inspection. <b>UT inspect pipe in 2007.</b>
02-08 02-09	016	FD18EL01 FD18SP02US	2002 Report: calculated time to Tmin is 7.92 cycles based on a single UT inspection. The 2007 RFO is 3 cycles since the inspection. Review of 2002 data for FD18EL01, & FD18SP02US, shows recommendations were made based on wear rates conservatively calculated from single low point measurements at weld counterbores. Significant margins exist on body of pipe and elbows. Defer this inspection to RFO 27 in 2008. At that time components will have ~1.7 cycles of operation under increased EPU flows. <b>Re-inspect elbow and downstream pipe in 2008 (4 cycles from 2002).</b>

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage  
Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LA: Large Bore Components selected (identified) from previous Inspection Results –continued**

Inspect. No.	Loc. SK.	Component ID	Notes /Comments / Conclusions
04-03	001	FD01TE05	2004 recommendation to inspect tee in 2008 based on the default wear rate of 0.005 inch/cycle. Flow on B FDW pump increases from ½ usage/standby for CLTP to full time usage and 80% of CLTP flow for EPU. <b>Re-inspect upstream elbow and tee in 2008.</b>
04-06	002	FD02RD01	2004 recommendation to re-inspect in 2011 based on the default wear rate of 0.005 inch/cycle. Flow on B FDW pump increases from ½ usage/standby for CLTP to full time usage and 80% of CLTP flow for EPU. <b>Re-inspect reducer with downstream elbow and tee in 2008.</b>
04-08	001	FD02TE01	2004 recommendation to inspect tee in 2007 based on the default wear rate of 0.005 inch/cycle. Actual point to point measurements from 1999 to 2004 indicate no wear. Given EPU operation, re-inspect with <b>upstream elbow and reducer in 2008.</b>
04-09	001	FD03SP01	2004 recommendation to inspect pipe section in 2011 based on a single inspection and the default wear rate of 0.005 inch/cycle. <b>Re-inspect in 2011.</b>
04-10	001	FD07SP02DS	2004 recommendation to inspect pipe section in 2008 based on a single inspection. <b>Re-inspect with downstream elbow in 2008.</b>
04-13	001	FD14EL03	2004 recommendation to inspect Row 13 pup piece to DS valve in 2008 is based on a single UT inspection. <b>Re-inspect in 2008.</b>
04-23	001	MSD9TE01 to MSD9TE08	2004 recommendation to inspect pipe section in 2010 due to localized wear directly under 2 small bore lines entering flow at top of pipe. <b>Re-inspect in 2010.</b>
04-23	001	MSD9EL05	2004 recommendation to inspect pipe section in 2010 base on a single inspection. <b>Re-inspect in 2010.</b>
05-12	011	FD08RD03	2005 Recommendation to inspect this component and downstream straight pipe in RFO28 –Spring 2010 due to increases flow velocity from EPU. <b>Re-inspect FD08RD03 and FD08SP02 in 2010.</b>
05-03 05-04 05-05	017	FD04RD01 FD04TE01 Cond Nzl 32A	During normal operation there is no flow in these lines. No current leakage is indicated since the upstream FCV repairs were performed during RFO24. This piping was inspected in RFO 25 to determine if past leakage has caused wear since the last inspections and to insure the condition of the piping for Extend Power Uprate conditions. 2005 Recommendation to use the Thermal Performance Monitoring (TPM) system to determine if flow is occurring in this pipe during normal operation. <b>The Thermal Performance Monitoring (TPM) system will be used as a trigger to determine if future inspections are required. The monthly TPM report will be monitored by the FAC program Engineer.</b>
05-06 05-07 05-08	018	FD05RD01 FD05TE01 Cond Nzl 32B	
05-09 05-10 05-11	019	FD06RD01 FD06TE01 Cond Nzl 32C	

**VY Piping FAC Inspection Program PP 7028 - 2007 Refuelling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LA: Large Bore Components selected(identified) from previous Inspection Results -continued**

**Turbine Cross-around Piping:**

Summary of previous Internal Visual UT & Repair History:

Line	Mat	Year Replaced	Internal Visual =V, Internal Thickness =UT, Repairs Performed =R									
			RFO16 S1992	RFO17 F1993	RFO18 S1995	RFO19 F1996	RFO20 S1998	RFO21 F1999	RFO22 S2001	RFO23 F2002	RFO24 S2004	RFO25 F2005
36"-A	GE**	1983		V	V	V	V				V	V
36"-B	GE**	1981	V	V	V	V	V	V			V	
36"-C	GE**	1981	V	V	V		V				V	V
36"-D	GE**	1983		V	V		V				V	
30"-A	P-22*	1985	V		V		V					
30"-B	C.S.	Original	V/UT/ R	V/UT/ R	V/UT/ R	V/UT	V	V		V		V
30"-C	P-22*	1993	V/UT/ R								V	
30"-D	P-22*	1985			V						V	

\*\* 36" straight pipe sections replaced with GE B50A242E, elbows on the B & C lines are original GE specification D50A67D, elbows on A & D lines are D50A67E (Tnom = 0.625 inch).

\* 30" A,B,C replaced with A691 CL22 (2-1/4Cr), Fittings A234 WP22. (Tnom. = 0.625 inch)

30" B remains GE B50A242D, fittings and GE D50A67D carbon steel (Tnom = 0.50 inch).

**2007 RFO:**

The last remaining carbon steel 30 inch, (30" B, upper east), line was inspected to confirm its condition prior to power uprate flows. Increased EPU flows and an expected drop in Moisture Separator efficiency will most likely result in resumption of FAC in this line. Results of the planned MS efficiency tests at EPU flows will quantify any drop in steam quality in these lines and provide some basis for estimating the increase in susceptibility to FAC damage. If the proposed testing at EPU flows shows no loss in MS efficiency, this inspection could be deferred until RFO27. For planning purposes:

Perform a complete visual inspection of 30" B line in RFO 26 will be planned to insure wall loss due to FAC has not resumed under EPU flow conditions. This will require coordination with planned LP turbine work scheduled for RFO26.

**VY Piping FAC Inspection Program PP 7028 - 2004 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LB: Components ranked high for susceptibility from current CHECWORKS evaluation and for identified as having the highest increases in flow velocities under EPU conditions.**

The current CHECWORKS wear rate calculations contain inspection data up to the 1999 RFO and wear rate predictions are current to the 2001 RFO. The 2001 and 2002 RFO inspection data has been entered into the CHECWORKS database. CHECWORKS predictive models for Piping FAC Inspection Program are updated as required per Appendix D of PP 7028. This is documented in CR-2005-2239. This is a procedure compliance issue. There are no operability concerns. Actual measured wear rates from 2001, 2002, 2004, and 2005 inspections are an order of magnitude less than the CHECWORKS predicted wear rates. If the 2002, 2004, and 2005 inspection data were incorporated into the models the CHECWORKS predicted wear rates would be reduced. Use of the un-updated CHECWORKS model results as a basis for inspection planning is conservative in that scoping decisions documented in the Inspection Location Worksheets were based on the CHECWORKS Predicted wear rates significantly greater than actual measure wear.

The updated wear rate calculations are in progress, and won't be complete in time to support the outage schedule milestone date for issuing the inspection scope for the 2007 outage. Based on a review of the 2001 thru 2005 RFO inspection data for components on the Feedwater, Condensate, and Heater Drain Systems, the CHECWORKS models still appear to over-predict actual wear. The existing model results will be used to rank components for inspection in 2007. The component selections will be reviewed upon completion of the CHECWORKS model updates.

**Feedwater System**

Listed below are components which meet the following criteria:

- a) Negative time to T<sub>min</sub> from the predictive CHECWORKS runs which include inspection data up to the 1999 RFO.
- b) No inspections have been performed on these components or the corresponding components in a parallel train since the 1999 RFO.

Component ID	Location Sketch	Location	Notes
FD07EL05	005	TB FPR Elev. 241	Comparable component on other train FD08EL04 was inspected in 1999 and results indicate minimal wear. After updating the Checworks model with newer data, assess need for inspections in 2008 RFO. (Note upstream components FD07RD02 and FD07SP03 will be inspected in 2007)
FD07TE01 FD07EL11	006	T.B Heater Bay Elevs 228 & 248	Components on other train were inspected in 1998. Results indicate minimal wear. Inspect FD07TE01, FD07EL01, and FD07SP11 in 2007 RFO.
FD07EL12	006	T.B Heater Bay Elev. 248	Feedwater heater replacement occurred in 2004 RFO. Informal visual inspections of internals and cut pipe profile indicated a stable red oxide and no distinguishable wear pattern. After updating the Checworks model with newer data, assess need for inspection
FD08TE01 FD08EL07	012	T.B Heater Bay Elevs 228 & 248	Intermediate components FD08EL06 & FD08SP08 were inspected in 1998. Results indicate minimal wear. After updating Checworks model with newer data, assess need for inspecting components.
FD08EL08	012	T.B Heater Bay Elev. 248	Feedwater heater replacement occurred in 2004 RFO. Informal visual inspections of internals and cut pipe profile indicated a stable red oxide and no distinguishable wear pattern.
FD15EL08	013	RX Steam Tunnel El. 266	Internal visual of elbow performed in 1996 during check valve replacement, no indication of wall loss at that time. Corresponding component on line 16" FDW-14 was inspected in RFO24. After updating Checworks model with inspection data, assess need for inspection in 2008 RFO.

VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage  
Inspection Location Worksheets / Methods and Reasons for Component Selection

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LB: Components ranked high for susceptibility from current CHECWORKS evaluation and/or identified as having the highest increases in flow velocities under EPU conditions - continued

Condensate System

Only one component was identified as having a negative time to T<sub>min</sub>. This was CD30TE02DS, the downstream side of a 24x24x20 tee on the condensate header in the feed pump room. The CHECWORKS prediction for the downstream side of the tee has a small negative hrs relative to the remainder of the components in the system and relative to the upstream side of the same tee. Other tees on the same header have been previously inspected and show no significant wear. The CHECWORKS model includes UT data up to the 1999 RFO. The inspections on this system performed in 2001, 2004, and 2005 indicate minimal wear.

Components CD30TE02 and CD30SP04 were inspected in 2004. Additional components downstream of condensate flow elements FE-102-2A and FE-102-2B on inlets to FDW pumps A & B were performed in 2005 with no significant wear observed. This inspection data will be input to CHECWORKS to better calibrate the model.

Moisture Separator Drains & Heater Drain System

No components identified as having negative times to T<sub>min</sub>. No components were selected for inspection in 2001, 2002, or 2004 based on high susceptibility. However, operation under HWC changes dissolved oxygen in the system. A separate CHECWORKS evaluation was performed to assess the differences in projected wear rates between Normal water chemistry and Hydrogen water chemistry. Selected HD components were inspected in 2002 to obtain pre-HWC operation wall thickness data. See Section LD below.

Extraction Steam System

Three components on this system with negative time to code min. wall: The piping is Chroma-Moly. ES4ATE01 & ES4ATE02, 30inch diameter tees inside the condenser have negative prediction (-3426Hrs.) for time to min wall. The negative times to t<sub>min</sub> may be conservative based on the modeling techniques used. Refinement of the model of this system is in progress. The negative time to t<sub>min</sub> is most likely a function of lack of inspection data vs. actual wear. Due to external lagging on this piping and the location inside the condenser, no components are selected for external UT inspection in 2007 based on high susceptibility.

Note the short section of straight pipe on line 12"-ES-1A at the connection to the 36 inch A cross around is assumed to be A106 Gr. B carbon steel is not modeled in CHECWORKS. This component was inspected in 2004 by external UT and an internal visual inspection from the 36" cross around line was performed in both 2004 and 2005.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LC: Large Bore Components Identified by Industry Events/Experience.**

Review of FAC related Large Bore Operating Experience (OE) and/or piping failures reported since April 2003

Date	Plant - Type	Description & Recommended Actions at VY
5/9/01	Grand Gulf - BWR	Pin Hole Leak in 4 inch carbon steel elbow in RHR min flow line. System has low use at VY (<2% of time). Perry also found thinning at elbow per C.Burton at CHUG meeting.) A review of VY drawings VYI-RHR-Part 14 Sht.1/1 and VYI-RHR Part 15 Sht.1/1 show elbows downstream of restriction orifices. Previous VY inspections downstream of orifices on HPCI and CS systems found no problems. Keep this OE listed for future consideration if similar industry events are identified.
1/15/02 CHUG Meeting	Surry 1-PWR	Leak in 8 inch Condenser drain header for 3 <sup>rd</sup> /4 <sup>th</sup> pt. FDW Heater vents. Also thinning in Gland Steam Piping inside the condenser and the 12" Condenser Drain header from MS Drain trap lines. The only large bore drain collector at VY is the 8 inch diameter low point drain header, line 8"MSD-9. This line is now part of the AST ALT boundary. Inspections of selected components on this line were performed during RFO24 with recommendations for repeat inspections in 2010 (Section LB above). Given this line is part of the ALT Boundary, inspect approx. 2 ft. long section at condenser wall during RFO26 (2007) MSD9SP07 at condenser nozzle 67 (Location Sketch 097)
6/26/03	Wolf Creek - PWR	OE16181: Leak in Main Feedwater Thermowell. The Thermowell is unused and was sealed with a pipe plug. Once the integrity of the plug was determined by RT, the main concern was potential for internal FME from the degraded Thermowell to affect downstream control valves. PWR feedwater piping more susceptible to FAC than BWR piping due to low DO. Keep this OE listed for future consideration if similar industry events are identified.
9/24/03	South Texas Project - PWR	OE17378: Pitting & internal wear found on discharge piping of Condensate Polishing System. Pipe is carbon steel, low water temperature (90 to 130F), neutral pH, and velocity of 12.2 Ft./sec. Tortuous flow path and control valves, wear may be impingement. PWR system Low dissolved oxygen. Equivalent system at VY is Condensate Demineralizer System which is low temp and screens per NSAC-202L as not susceptible to FAC based on temperature. No OE on BWR Condemin systems.
10/10/03	Browns Ferry 3 -BWR	6/04 CHUG Meeting PER: Failure of No.2 Extraction Steam bellows inside condenser caused collateral damage in No.3, No.4A, & No.5B east bellows. In service for only 2-1/2 cycles. Failure due to welds/weld flaws in bellows. Additional erosion found in the carbon steel Extraction Steam lines inside the condenser was found during the unplanned mid-cycle outage for bellows repairs. At VY, the Extraction Steam piping inside condenser is Cr-Mo. The bellows were replaced in 1995. The System Engineer performed limited bellows inspections in RFO25. No new actions with respect to FAC for this OE.
10/17/03	Duane Arnold -BWR	OE17300: Through wall leak on 8 inch pipe between 6A feedwater heater and condenser. The pipe was chrome-moly. Temporary pipe configuration installed prior to replacing feedwater heater for power uprate. Cause of leak was droplet impingement erosion from use of bypass control valve. No actions required for VY. However, it should be noted that chrome-moly pipe is not immune to droplet impingement erosion.
10/31/03	Clinton -BWR	OE17412 / OE18478: Through-wall leaks in 2A/ B heater vent lines to the condenser (larger bore lines assumed given description of backing rings in piping). Apparent cause attributed to steam jet impingement from wet steam. Equivalent line at VY is common 4 inch feedwater heater vent line for No.4 FDW heaters. AT VY this line is included in the SSB database since it connects to (2) 2-1/2" lines. Inspect this line at the condenser in RFO26 in 2007 [Inspection No.07-SB09]

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LC: Large Bore Components Identified by Industry Events/Experience - continued.**

Date	Plant - Type	Description & Recommended Actions at VY
11/07/03	Braidwood 2-PWR	OE17454: Wall thinning found on FDW pump discharge nozzles and extending into downstream pipes on all 3 FDW pumps. Material has high chromium content. PWR feedwater system chemistry has low D.O. therefore more susceptible to wall loss due to single phase FAC than BWR feedwater piping. At VY all three feedwater pump discharge nozzles and downstream piping have multiple inspection data. No further actions are anticipated from this OE.
11/19/03	Hope Creek - BWR	OE17700: Pinhole leak and wall thinning in 8" in carbon steel Extraction Steam supply line to Steam Seal Evaporator. Location of wear is downstream of pressure safety valves. Apparent Cause of leak & wear is due to liquid droplet impingement due to high flows from failure of pressure safety relief valves. No equivalent configuration at VY.
1/24/04	LaSalle 1 - BWR	OE17199 / OE18381: Through-wall holes in extraction steam piping inside condenser. Location of holes at inlet nozzles to No.2 FDW heaters located in the neck of the condensers (2 <sup>nd</sup> lowest stage). All 12 nozzles are C.S. with A335-P11 upstream piping. VY has only the No. 5 FDW heaters in the neck of the condenser. The No. 5 FDW heaters were replaced with Chromo-moly shells and ES piping nozzles. ES piping is A335-P11 or equivalent which is FAC resistant. No further actions are anticipated from this OE.
2/17/04	Peach Bottom 2 - BWR	OE18637: On line leak in 10 inch main steam drain line header to the condenser. Hole was located directly below the connection of 1" main steam lead drain. The header was replaced with 1-1/4 Chrome material approx. 5 years before the leak. Also, R.O.s in steam drains were modified. The cause was attributed to steam impingement. Additional information to follow after next RFO. The only large bore drain collectors at VY are the 8 inch diameter low point drain header, line 8"MSD-9, and line 3"-MSD-4 near the condenser. Flow is through steam traps and LCVs vs. a continuous flow through a restriction orifice. These lines are now part of the AST ALT boundary. For MSD-9, inspection of the entire bottom of this header under the MSD lines was performed during RFO24 with recommendations for repeat inspections in 2010. <b>Inspect 8"-MSD-9 at the Condenser in RFO26 (2007). For line 3"-MSD-4, see Small Bore OE in section SC below.</b>
3/17/04	Farley 2 - PWR	OE18059: Nameplate Screws Holes Found Extended Into Flow Nozzle Pipe. 16 in. Sch.60, A106 Gr.C. Evaluated as a flaw and found acceptable. Only a concern if FAC wear is occurring in the pipe at the location of the nameplate. VY inspections to date for FDW and Condensate flow elements show no wear in pipe. No further actions for this OE.
3/27/04	Perry -BWR	6/04 CHUG PER: Through wall leak in a 12" diameter drain header (Main Steam, Reheat Steam, Extraction Steam, and Misc Drains collector) connecting to the condenser. The only large bore drain collectors at VY are the 8 inch diameter low point drain header, line 8"MSD-9, and line 3"-MSD-4 near the condenser. Flow is through steam traps and LCVs vs. a continuous flow through a restriction orifice. These lines are now part of the AST ALT boundary. For MSD-9, inspection of the entire bottom of this header under the MSD lines was performed during RFO24 with recommendations for repeat inspections in 2010. <b>Inspect 8"-MSD-9 at the Condenser in RFO26 (2007). For line 3"-MSD-4 See Small Bore OE in section SC below.</b>
7/05/04	Oni-1 -PWR (Japan)	OE19492: OE describes wall thinning in PWR feedwater components between the feedwater isolation valves and the steam generators. No leaks, wall thinning was found through planned UT inspections. Components will be replaced with the same materials and additional inspections (increased frequency) will be performed. PWR feedwater piping more susceptible to FAC than BWR piping due to low DO. VY inspects final feedwater piping components. No wear found to date.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LC: Large Bore Components Identified by Industry Events/Experience - continued.**

Date	Plant - Type	Description & Recommended Actions at VY
7/30/04	Darlington Unit 4 - PHWR	INPO Event No.934-040730-1. Leak in 10 inch diameter Sch.60, HP Drains manifold. Material is low chrome-moly (2.25/1) alloy carbon steel. Darlington plans to increase inspection scope for HP Drains manifold piping. Cause of leaks attributed to liquid impingement. [ See 2/17/04 Peach Bottom 2 OE and 3/27/04 Perry OE evaluation of for VY above. Also, note that this OE demonstrates that Cr-Mo P22 material may not be the ultimate solution if liquid impingement is occurring. ]
8/9/04	Mihama 3 - PWR	OE19368/OE18895: Rupture of Condensate line downstream of restriction orifice. PWR system highly susceptible to single phase FAC due to low DO. Similar region of system as 1986 Surry event (5 fatalities). Based on info gathered by INPO/CHUG/FACnet the location was omitted from previous inspections due to clerical error, once discovered management missed opportunity to inspect and deferred inspection until 9/04. Too late. Lesson: make sure all highly susceptible locations get inspected. PWR Condensate/feedwater piping is much more susceptible to single phase FAC than BWR with O2 injection. A review of previous inspections DS of Flow Elements at VY shows: Condensate piping at and downstream of FE-102-2A & -2B was inspected in RFO25(2005) and piping at and downstream of FE-102-2C was inspected in RFO22(2001). Also feedwater piping downstream of FE-6-11A was inspected in RFO23(2002). See section LF below for discussion of Flow Elements in lower temperature Condensate piping.
8/10/04	Sequoyah 2 - PWR	OE19074: Leak in Heater Drain Tank Recirculation line downstream of the recirc. nozzle of the automatic recirculation valve. Suspected leakage by Normally Closed Valve. No similar configuration at VY.
8/26/04	Palo Verde 3 - PWR	OE20388: Through wall leak found on a 10" inch flashing tee cap on the LP feedwater heater drains. Problems with inspection of flashing tees in program. Only 14 out of 153 susceptible locations have UT data at Palo Verde 1,2,3. At VY there are 4 flashing tees D.S. of LCV-103-23A to -23D on the Moisture Separator Drain system at VY. These along with the blind flanges were replaced with Cr-Mo in 1992. The only other flashing tees at VY are located on the FWD pump min flow lines at the condenser. These have welded pipe caps. Inspection of all 3 lines 6"FDW-4, 6"FDW-5, and 6"FDW-6 performed in RFO25. No other actions for this OE.
9/18/04	Catawba 2 - PWR	OE19350: Wall thinning found four different areas on FDW piping. Two areas are not considered specific to Catawba: 1)Area where main feedwater bypass reg valves reenters the feedwater header and 2) downstream of the main feedwater reg valves. PWR feedwater system chemistry has low D.O. therefore more susceptible to wall loss due to single phase FAC than BWR feedwater piping. At VY area 1) does not exist (bypass lines dump to the condenser). 2) Inspections have been performed upstream and downstream of both main feed reg. valves. Inspections downstream of FCV-12B (FD08RD03 & FD03SP02) were performed in RFO25. Inspections downstream of FCV-12A planned for RFO26 given the increased velocities under EPU. No further actions are anticipated from this OE.
9/24/04	Palisades - PWR	OE19494: Wear found in carbon steel 12" Sch 40, Extraction Steam line downstream of bleeder trip valve. Wear found through FAC inspections. No through wall leak. This OE identifies potential for FAC damage in ES piping and problems with partial line (selected component) replacements. ES piping at VY is low alloy A335-P-11 Cr.Mo piping which is FAC resistant. No further actions for this OE.



**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

LC: Large Bore Components Identified by Industry Events/Experience - continued.

Date	Plant - Type	Description & Recommended Actions at VY
10/12/04	Prairie Island 1 - PWR	OE19385: Pipe Failure Internal to the Main Condenser Found During Outage Inspection. Failure in 14 x 8 reducing elbow and wall thinning in 8 inch pipe on line connecting heater drain tank to condenser. Failure discovered during routine condenser inspections before tube damage had occurred. VY performs internal condenser walkdowns each RFO with additional inspections during equipment maintenance. At VY piping attached to the condenser either has impingement plates to protect the tubes or spargers internal to the condenser to disburse flow. Extraction steam piping inside the condenser is Cr-Mo. Material. Visual inspection of the condenser steam space will be performed by System Engineering. No new inspections will be performed under the FAC Program for this OE.
11/3/04 (Note Follow-up present at 8/05 CHUG Meeting)	Duane Arnold - BWR	OE19701: Wall thinning downstream of Torus Cooling Test Return Header Isolation Valve. Apparent cause was cavitation erosion due to throttling in valve during HPCI & RCIC testing. At VY, the equivalent valves are V10-34A & 34B. The degree of cavitation present is dependent of the system design and may vary from plant to plant. Previous UT inspections at VY were performed on valve bodies and downstream reducers in early 90s. No significant wear was found. <b>Consider inspection of downstream piping in RFO27 if additional OE warrants it.</b>
2/17/05	Clinton - BWR	OE20246 and CHUG PER 1/06: Through wall leaks found in 12", 20", and 30" Extraction Steam Piping inside the condenser. These lines were not in the FAC program according to the Heat Balance they carry superheated steam. Equivalent piping at VY is in the FAC program and is Cr-Mo, A335 P-11
2/26/05	Calvert Cliffs 1 - PWR	OE20127: Through wall leak in 6 inch steam vent header from MSR drain tank to hot reheat header. Location of leak was at the end of elbow which had a backing ring. Leak location was at the backing ring. At VY, there are no backing rings in piping systems containing primary steam/water. Also, there are No MSRs at VY.
5/23/05	Vogtle Unit 2 -PWR	OE20793: Extraction Steam expansion bellows failure inside condenser caused collateral damage to feedwater heater shroud and condenser tubes. Not FAC. No further actions require for this OE.
6/05 CHUG Meeting	TEPCO Fukushima Dai-1 (2F-1) - BWR	Wall thinning downstream of a restriction orifice in the CRD pump supply line from Condensate System. Pipe Size 100A (approx. 4.5 inch O.D.). Location is DS of Control valve and restriction orifice on supply line to CRD pumps from the condensate system. VY has a similar configuration but without the Restriction Orifice. This line screens out of the VY FAC Susceptibility Evaluation based on low temperature. Comparison with VY: 1. Condensate supply is upstream of the oxygen injection point, same at VY. 2. MOV is a globe valve the same size as pipe. The valve is operated at 8% open to control flow with a restriction orifice just downstream of the valve. VY has a smaller size control valve than the main line. A 1-1/2" control valve (LCV-102-1A-3) with expanders from 1-1/2" to 2-1/2" then to the 4" diameter line with no restriction orifice. 3. Supply line is downstream of low pressure condensate pump. At VY supply is directly from hotwell. This results in a higher DP across the MOV & RO at TEPCO than across the LCV at VY. TEPCO has higher potential for cavitation and/or flashing due to the higher DP.  At VY, UT measurements on the valve body were performed 1992, but no measurements on the downstream piping. TEPCO root cause was FAC with <u>cavitation contributing at the RO</u> . Given there is no RO at VY and the LCV is operated at 60% open. The potential for a similar situation at VY is significantly less. Scope out possible inspection locations on piping down stream of LCV-102-1A-3 during RFO26 in 2007.
6/05 CHUG Meeting PER	Wolf Creek - PWR	Eroded elbow found in 12 inch LP feedwater heater drain line inside condenser. Erosion was external to pipe from main steam dump to condenser. No equivalent piping at VY. At VY only the No.5 FDW Htrs. are in the neck of the condenser. Heater drain piping is external to the condenser. The extraction steam piping inside the condenser has external lagging for protection and thermal efficiency.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage  
Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LC: Large Bore Components Identified by Industry Events/Experience - continued**

Date	Plant - Type	Description & Recommended Actions at VY
6/05 CHUG Meeting	Hatch Units 1 and 2 - BWR	Pinhole leaks in 3 inch line between Steam Packing Exhauster Drain Tank and Condenser in both units. The leak locations were at the first elbow downstream of the tank level control valves. The equivalent piping at VY is 6"C-44 at condenser nozzle 63. This line screens out of the VY FAC Susceptibility Evaluation based on low temperature. VY has two LCVs in parallel vs. the single valve on each of the Hatch units. Given that a leak in this line would affect condenser vacuum and challenge plant availability, inspect locations downstream of valves LCV-102-8-1 and LCV-102-8-2 in RFO26 (2007)
6/22/05	Callaway - PWR	OE19965: Failure of the carbon steel body section of an internal pipe flow element manufactured by Badger Meter blocked flow in a Heater Drain tank Pump discharge line. A separate evaluation of this OE was performed for VY. 3 Flow elements in the Condensate System; FE-102-2A to -2C have been identified as the same construction. UT inspections of piping US, the pipe at the flow element, and DS of each of the flow elements shows no wear is occurring. This is not a pressure boundary issue. An ER will be generated to develop the best scheme for inspection and evaluation of the internal portions of the pipe flow elements.
6/23/05	Palo Verdi Unit 1 PWR	1/06 CHUG PER: Leak on 8"x 12" expander downstream of level control valve on MSR Drain tank to Heater Drain tank. No MSR or heater drain tank at VY. This is high pressure piping. The closest components would be the Moisture Separator Drain Piping down stream of LCV-103-24A to 24D. This piping is A335 P-22 material. Other components would be piping downstream of Heater Drain System LCV-103-1A-1/1B-1, LCV-103-2A-1/2B-1, and LCV-103-3A-1/3B-1. Piping downstream of these valves is either chrome moly or stainless steel. No new actions with respect to FAC for this OE.
8/16/05	Dresden 3 - BWR	OE21421/OE21968 Loss of Main Condenser vacuum due to air in leakage and a degraded SJAE train. Age related degradation of the 2 <sup>nd</sup> stage steam jets at Dresden. VY replaced the SJAE nozzles in 1993 (JO 92-0140). However, US & DS piping is original. ER 06-1190 was written to evaluate SJAE replacement including the need for additional FAC inspections of the piping. With respect to the vent line internal to the condenser at Dresden which experienced external wear due to steam erosion, the equivalent section of piping at VY is stainless steel. The need to establish PMs for AE lines in the condenser will be addressed in the response to ER 06-1190.
9/26/05	Hatch Unit 1 - BWR	OE21591: Through wall leak in a Fisher control valve body. MSR Reheater 2 <sup>nd</sup> Stage High Level Dump. Hole in the 1 inch thick valve body was attributed to leakage past the seat. The valve had been modified for power uprate. The trim was changed to avoid installing a larger actuator on the valve. This OE was forwarded to the Systems/TPM Engineer. The TPM system will be used to identify leakage by normally closed valves to the condenser.. The monthly TPM report will be monitored by the FAC program Engineer.
1/06 CHUG Meeting	Surry - PWR	Hidden spool piece discovered. Plant replacement practices in two separate local material replacements (Cr-Mo) on a 6 inch line at the upstream elbow and the downstream elbow resulted in a carbon steel spool piece remaining in the line. This situation highlights importance of configuration control, potential hazards of partial replacement strategy, and the need for alloy sampling.
1/06 CHUG Meeting	Susquehanna Unit 2 - BWR	Through wall damage found in 3" and 4" diameter FW heater vent piping and associated condenser nozzles during pipe replacement activities. Caused increased condenser in-leakage. Heater Vent Piping at VY is monitored for FAC in Small Bore Program.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
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**LD: Large Bore Components Selected to Calibrate CHECWORKS**

The CHECWORKS wear rate calculations have been upgraded to include the 96, 98, & 99 RFO inspection data. The 2001 and 2002 inspection data has been loaded however wear rate analyses have not been completed at this time.

Condensate:

In 2001 components on the higher temperature end of the Condensate System were inspected to calibrate the CHECWORKS models. The inspection data indicate minimal wear and should reinforce the assessment of low wear in the Condensate System. Additional inspections were performed on lines CD-30, CD-31 and CD-32 in 2004 and 2005. There is no inspection data on line 20"-C-28 between the E-4-1B and E-3-1B feedwater heaters for CHECWORKS calibration. Given the increase in operating temperature & flows for EPU, inspect components CD28EL04 & CD28SP03US in RFO26 (2007).

Heater Drains/ Moisture Separator Drains:

Prior to the 2002 RFO there was limited inspection data for the Heater Drain system. The current CHECWORKS models (Pass 1 and some Pass 2) indicate low wear rates. During 2002 a number of new inspections were performed on the carbon steel piping upstream of the level control valves (LCV) to obtain a baseline prior to operation on hydrogen water chemistry. The 2002 inspection data indicate significant margin for future wear in the components inspected.

Piping downstream of the level control valves (LCV) for the feedwater heaters is FAC resistant material, except for inlet to No.5 Feedwater heaters. The carbon steel piping downstream of the normal flow LCV-4B-1 will be inspected in RFO26. Additional components on lines which do not already have inspection data will be inspected in RFO26. (2007) are listed below.

Inspection	Component ID	Loc. Sketch	Location	Previous Inspections	Reasons / Comments / Notes
2007-27	HD1AEL06	043	T.B. Htr. Bay Elev. 235.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-28	HD1ASP08	043	" " "	NO	
2007-29	HD3BTE01	051	T.B. Htr. Bay Elev. 239.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-30	HD3BEL02	051	" " "	NO	
2007-31	HD3BSP05US	051	" " "	NO	
2007-32	HD5ATE01	045	T.B. Htr. Bay Elev. 239.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-33	HD5ASP06	045	" " "	NO	
2007-31	HD3BSP05US	045	" " "	NO	
2007-32	HD25RD02	053	T.B. Htr. Bay Elev. 253	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-33	HD5ASP02	053	Inlet to E5-1-B	NO	
2007-34	HD12TE01	057	T.B. Htr. Bay Elev. 229.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-35	HD12SP01	057	MS-1-1A drain	NO	
2007-36	HD12EL06	058	T.B. Htr. Bay Elev. 230.	1989	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-37	HD12SP07US	058	MS-1-1B drain	1989	

Main Steam and Feedwater:

None for RFO26.

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**1E: Large Bore Components subjected to off normal flow conditions identified by turbine performance monitoring system (Systems Engineering Group).**

The Systems Engineering Production Variance Report for January 1 to January 31, 2006 lists 3 of the 10 normally closed Turbine Bypass Valves as suspected of having seat leakage. Elevated tailpipe temperatures (Approx. 250F vs. Approx 200F) have been recorded on valves 1, 5, & 7. (See Attached Plot) The tailpipes are 10 inch diameter carbon steel lines connecting directly to the condenser. Each line ends inside the condenser at multi-stage restriction orifice supplied by GE. This indicates that any pressure drop in these lines should occur inside the condenser. The steam temp at the bypass valve is approx 540F. The 250F temp measured on the three suspected leaking lines is approx. 50 F above the lines considered as not leaking. Any water condensing out of the steam should occur in the restriction orifices inside the condenser. Consider inspections on these lines only if temperatures continue to increase.

Since startup from 2005 (RFO25), only one small bore valve and no steam traps have been identified (to date) using the Turbine Performance Monitoring (TPM) system. The small bore valve is LCV-101-3B this is addressed in Section SD below. Piping Downstream of this valve, 2"-ES-9B is Cr.-Mo steel and is resistant to FAC. However, if new data indicates leaking valves then additions to the outage scope may be required.

**1F: Engineering Judgment / Other**

Nine ASME Section XI Class 1 Category B-J welds are to be inspected by the FAC program per Code Case N-560 in lieu of a Section XI volumetric weld inspection. The VY ISI Program Interval 4 schedule for inspection of these welds is as follows:

Refueling Outage	Section XI ISI Program Weld ID	Description	FAC Program Components
Spring 2004 (RFO24) Interval 4 Period 1, Outage 1.	FW19-F3B FW19-F3C FW19-F4 FW21-F1	upstream pipe to tee tee to reducer reducer to pipe tee to pipe	"A" Feedwater on Sketch 010 FD19TE01 FD19RD01 FD19SP04 FD21SP01
Fall 2011 (RFO29) Interval 4 Period 3, Outage 6.	FW18-3A FW20-3A FW20-F1 FW20-F1B FW18-F4	upstream pipe to tee tee to reducer reducer to pipe horizontal pipe to pipe tee to pipe	"B" Feedwater on Sketch 016 FD18TE01 FD20RD01 FD20SP01 FD18SP04

**Extended Power Uprate (EPU)**

Feedwater system:

EPU evaluation for Feedwater System: The primary focus of work to date (for PUSAR and RAIs ) was on velocity changes given only slight increases in temps and no chemistry changes. With all 3 FDW pumps running the 16 inch diameter lines to the 24 inch FDW header have approx.  $[1.2(2/3) = 0.80]$  20% reduction in velocity. Velocities in the remainder of the system increase approx. 20%. The highest velocities are at the 10 inch reducers upstream and downstream of the FDW REG valves. The expander and downstream piping have multiple inspection data with FD07RD03/FD07SP03 last inspected in 2001 and FD08RD03/FD08SP02 last inspected in 2005. Both of these segments should be re-inspected after some time of operation at EPU flows. Assuming EPU starting early in 2006, inspect components FD07RD03 and FD07SP03 in 2007 for a post EPU measurement.

Continued

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

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**LF: Engineering Judgment / Other -continued**

Condensate System:

Given the 8/04 Mihama event: consider additional components in the condensate system for inspection :  
downstream of flow orifices & venturies:

FE-102-4 and downstream pipe on 24"C-8 venturi type (TB condensate pump room overhead) Given low operating temperatures and upstream of oxygen injection point, <b>scope out and evaluate for inspection in RFO27 in 2008</b>
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FE-52-1A to FE-52-1E on Condensate De-mineralizer System ( Restriction Orifices). Given low operating temperatures and upstream of oxygen injection point, <b>scope out and evaluate for inspection in RFO27 in 2008</b>
--

FE-102-7 and downstream pipe on 14"C-21 venturi type TB Heater Bay El 237.5 Given low operating temperatures and used for start-up, <b>scope out and evaluate for inspection in RFO27 in 2008</b>
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Extraction Steam

All Extraction Steam piping is A335-P11, a 1-1/4 chrome material, except for a short carbon steel stub piece in line 12"-ES-1A at the connection to the 36" A cross around line. Internal visual inspections of this stub piece were performed with the cross around inspection in RFO24 and RFO25. Also an external UT inspection of ES1ASP01 was performed in RFO24.

**LG: Piping Identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)**

Word searches of open work orders on EMPAC were performed for the following keywords: trap, leak, valve, replace, repair, erosion, corrosion, steam, FAC, wear, hole, drain, and inspect. No previously unidentified components or piping were identified as requiring monitoring during the Fall 2005 RFO.

Note: the internal baffle plate in Condenser B for the AOG train tank return line to the condenser was to be replaced in RFO 25 (ER 04-1454/ ER 05-232 /ER 05-0274). Erosion on baffle plate is from condenser side (not piping side). This work was deferred from RFO25. See W.O. 04-1462.

Internal visual inspection of LCV-103-3A-2 during RFO 24 indicated some type of casting flaw. The System Engineer suspects possible leaking by the normally closed valve. The downstream piping was last inspected in 1990. The line typically has no flow. Re-evaluate using the Thermal Performance Monitoring System Data and consider inspection of downstream piping in RFO27.

A through wall leak in the steam seal header supply line 1SSH4 was discovered on 9/24/04 (CR-VTY-2004-02985). A temporary leak enclosure was installed and a planned permanent repair was scheduled for RFO25. The leaks are on the bottom of un-insulated piping upstream of the gland seal. Field inspection of the leak location shows that the piping at the leak sloping down to the gland seal, not sloping up to the seal as shown on the design drawings. UT data on the top of the piping near the leak shows full wall thickness. At this time, the exact mechanism which caused the leak is not known. Additional inspections to determine the extent of condition on the 3 other gland seal steam supply lines were recommended. Inspection of the 90 degree elbow and approx. 2 ft. of downstream piping on lines 1SSH3, 1SSH4, 1SSH5, and 1SSH6 was planned for RFO 25. Also based on industry OE and similar piping geometry, inspection of 2 of the SPE lines 1SPE3 and 1SPE5 was planned for RFO 25. These inspections were deleted from the RFO26 scope due to higher priority LP turbine work. (References 9 & 10). Perform these inspections in RFO26. See Section LH below.

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**Small Bore Piping**

**SA: Susceptible piping locations (groups of components) contained in the Small Bore Piping data base which have not received an initial inspection.**

Locations on the continuous FDW heater vents to the condenser on the No. 3 heaters were inspected in 2002. The continuous vents on the No. 4 heater were installed new in 1995. The start up vents operate less than 2% of operating time. No wear was found in previous inspections on Heater Vent piping from the No.1 & 2 heaters. Given that and the lower pressure in the No. 4 heater shells, a complete inspection of the remainder of the No. 4 heater vent piping can be deferred. The existing small bore data base and the piping susceptibility analysis is under revision. No additional components from Revision 1 of the data base will be inspected.

**SB: Components selected from measured or apparent wear found in previous inspection results.**

Small Bore Point No. 20. 2-1/2" MSD-6 @ connection to condenser A at Nozzle 33 (Inspection No. 96-SB01 identified a low reading at weld on stub to condenser). Upstream valves are normally closed. TPM system does not indicate any abnormal flow. Inspect this piping in RFO 26

**SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.**

Date	Plant - Type	Description & Recommended Actions at VY
4/29/99	Darlington 1 - PHWR	Severed line at steam trap discharge pipe at threaded connection. Equivalent to HHS system at VY. (INPO Event 931-990429-1). Threaded connections typically on condensate side of HHS piping. Lower energy/consequence of leak. <b>Include HHS piping in FAC Susceptibility Review, and in the Small Bore Database. Include ranking and consequences of failure.</b>
9/1/01	Peach Bottom 3 -BWR	(From 1/14/02 CHUG Meeting), leak on 1 inch Sch. 80 line from Off Gas Re-combiner pre-heater drain line to condenser. An additional review of AOG steam supply system was performed and incorporated into the FAC Susceptibility Review. <b>Update small bore database to include ranking and consequences of failure.</b>
1/15/02 CHUG Mtg.	Hatch1/2 -BWR	Condenser in leakage due to through wall erosion (external) of 1-1/2 inch "slop" drains lines inside the condenser. Lines in each unit were cut and capped, similar events at Byron Unit 1 (OE 12809) and Columbia (OE12145). Limerick & Dresden. VY slop drain lines inside condenser were walked down during RFO24 and RFO25. Some external erosion on piping and supports was found. <b>Slop Drain Issue. Coordinate with Systems Engineer</b>
4/2/03	Peach Bottom 3 -- BWR	OE16287: Steam leak found on 3"x2" elbow on RFP Turbine sealing steam system small bore piping. Leak was on piping susceptible to FAC but was not included in the scope of the FAC Program. This occurred as the piping was part of a vendor supplied skid and was not reflected on the drawings used for the FAC program. The VY FAC Susceptibility Evaluation has been updated to include all known vendor supplied piping (VY-RPT-05-00012, Rev.0.)
10/31/03	Clinton -BWR	OE17412 / OE18478: Through-wall leaks in 2A/B heater vent lines to the condenser (larger bore lines assumed given description of backing rings in piping). Apparent cause attributed to steam jet impingement from wet steam. Equivalent line at VY is common 4 inch feedwater heater vent line for No.4 FDW heaters. This line is included in the SSB database since it connects to (2) 2-1/2" lines. Inspection priority will be determined in the small bore ranking and prioritization.

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SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI  
CHUG. - continued

Date	Plant - Type	Description & Recommended Actions at VY
11/7/2003	Limerick 1, BWR	OE17818: Through wall leak in 1 inch drain line back to condenser off ES piping at the connection to the large bore line. Normally no flow in line due to N.C. valve. Piping downstream of valves to condenser on all 3 lines was scheduled for replacement. Location US of valve was thought not to be susceptible. ES piping at VY is FAC resistant A335-P1. Lesson from this event is that any carbon steel line in a wet steam system is susceptible & should be monitored. Also full line replacement insures all susceptible piping is replaced.
1/16/04	Clinton - BWR	OE17654: Potential trend for adverse equipment condition downstream of orifices. (Ref. Previous experience a Clinton with CRD pump min flow ROs) Inspected CRD pump min flow orifices also piping DS of RO-64-2 in RFO25. Additional inspections will be performed if further OE is obtained.
12/06/04	V.C. Summer - PWR	OE19798/OE20075: Complete failure of a 1 inch ES line at the location of a previously installed Fermanite clamp repair. Previous leak at weld installed in May 2004. See presentation at January 2005 CHUG meeting. (They did not do UT on the pipe to assure structural integrity prior to installing the clamp.) Problems with leaving CS in system DS of material replacements. Review of previous replacements at VY has identified 2 locations at the condenser with similar configuration. Planned Inspections Nos. 07-SB04 and 07-SB05.
2/3/04	Columbia - BWR	6/04 CHUG Meeting PER: Through wall leak in 2" CS A106 Gr.B section of Misc drain line from bleed steam trap station to collection header. Location of leak is just upstream of where discharge piping enters the into the collection header. Piping upstream of location is stainless steel. At VY MSD piping downstream of ST-60A to 60D and LCV-101-38A to 38D connecting to 8"MSD-9 is carbon steel and is included in the Small bore Piping Database. Most locations have already been inspected. No further actions for this OE.
2/17/04	Peach Bottom 2 BWR	OE18637: On line leak in 10 inch main steam drain line header to the condenser. Hole was located directly below the connection of 1" main steam lead drain. The header was replaced with 1-1/4 Chrome material approx. 5 years before the leak. Also, ROs in steam drains were modified. The cause was attributed to steam impingement. Additional information to follow after next RFO. The only large bore drain collector at VY is the 8 inch diameter low point drain header, line 8"MSD-9. Flow is through steam traps and LCVs vs. a continuous flow through a restriction orifice. This line is now part of the AST ALT boundary. Inspections of the entire bottom of this header were performed during RFO24 with recommendations for repeat inspections in 2010. Also similar SSB configuration on 3"-MSD-4 near condenser. Inspect 3"-MSD-4 from the two 2 steam trap drains connections to the condenser.
3/2/04	Calvert Cliffs Unit 1 - PWR	OE18730: Though wall leaks in MSR drain piping at socket welded elbow fittings. Piping was replaced with Cr-Mo in the early 1990s. Cause attributed to liquid impingement. Plant is considering changing piping to eliminate SW elbows by using pipe bends. To date at VY: no leaks have been found on Cr-Mo piping replacements. No New action required for this OE.
5/9/04	Susquehanna Unit 2 - BWR	1/05 CHUG Meeting PER: Through wall leak in 1" Main Steam Bypass line drip leg drain to the condenser. The leak was at coupling joint at the condenser. The piping was replaced with P-22 in 1992. However, the coupling was not replaced at the condenser nozzle. A similar situation exists at VY for replacement of 2"MSD-406 (Steam Leads Drains) at the condenser. Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Insp. 07-SB04 at condenser Nozzle 35)

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**SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG. - continued**

Date	Plant - Type	Description & Recommended Actions at VY
7/4/04	Hope Creek - BWR	1/05 CHUG Meeting PER: Through wall leak in 2" turbine bleed steam drain from HP extraction. Piping and coupling was 2-1/4% Cr-Mo. Leak attributed to abnormal fit-up into the coupling. Installation quality issue not FAC wear. No further actions for this OE.
10/1/04	Confrentes (Spain) - BWR	1/05 CHUG Meeting PER: Leak in 1-1/2" P-22 pipe bend on a turbine driven (feedwater) pump drain line in the Main & Re-Heated Steam System immediately downstream of an orifice. The only steam turbine driven pumps at VY are the HPCI and RCIC pumps. These pumps have low usage. No further actions for this OE.
12/8/04	TEPCO Fukushima1-4 - BWR	1/05 CHUG Meeting PER: Through wall leak in drain line from steam turbine driven feedwater pump steam supply line. The drain line runs to the condenser. The only steam turbine driven pumps at VY are the HPCI and RCIC pumps. These pumps have low usage. No further actions for this OE.
1/05 CHUG Meeting PER	River Bend - BWR	Through wall leak at condenser nozzle on the 2-1/2" emergency high level drain line from the steam seal evaporator drain receiver tank to the condenser. Sections of this line are stainless steel, but the condenser nozzle is carbon steel. The apparent cause is using this high level drain line for normal level control increased wear in the CS nozzle. The equivalent piping at line at VY is 3" and 6" C-44 downstream of valves LCV-102-8-1 and LCV-102-8-2 to condenser nozzle 63. Given that a leak in this line would affect condenser vacuum and challenge plant availability, inspect locations downstream of valves LCV-102-8-1 and LCV-102-8-2 in RFO26 (2007).
1/21/05	D.C. Cook 1 - PWR	OE20165: Leak in Middle Heater Drain Pump Emergency Leakoff Line assumed to have no flow when the pump was not running. Geometry different from North and South Heater Drain Pumps. However flow, was in the 1 inch line when the pumps were not running. Incorrect assumption in the FAC SSE. Assumption that pump was not in service and no flows in line. No additional inspections as a result of this OE. However, one of the DC Cook Corrective Actions should be performed at VY: "Assumptions used in the SSE will be re-validated to confirm they are still accurate". Generate PCRS/WT or ER to have reviews performed by Systems Engineers and OPS.
2/4/05	TEPCO Kashiwazaki Kariwa (K-1) - BWR	6/05 CHUG Meeting Presentation and follow up at 1/06 CHUG Meeting PER: Through wall leak at MS Leads Low Point Drains connecting to the condenser. Pipe 50A (approx. 2 inch dia.) Pipe material is Cr-Mo. Steel. Leak location is approx. 9 meters downstream of orifice in pipe on extrados of exit from a 90 degree SW. TEPCO root cause is two-phase flow incorporating droplet induced erosion. VY has similar geometry. Piping at VY was originally carbon steel and was replaced with Cr-Mo in 1998. TEPCO piping has a more tortuous path to the condenser (tee and 8 SW elbows) while VY only has the SW tee. "TEPCO plans to replace the line and move the RO into the condenser. Consider inspection of Cr-Mo Piping immediately DS of the SW tee in either 2008 or 2010 due to expected increase in drain flows at EPU conditions. CS stub piece at the condenser and upstream Cr-Mo piping will be inspected in RFO26 (2007).
3/1/05	McGuire 2- PWR	OE20163: Though-wall leak in a 2 inch carbon steel vent line on the MSR heating steam vent line. Caused by FAC when flashing occurred upstream of RO (design location). No MSRs or equivalent locations at VY. At VY the only Restriction Orifices are in the FDW Heater Vent System Continuous vent lines. These are already in the scope of the FAC program.



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**SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG. – continued**

Date	Plant - Type	Description & Recommended Actions at VY
6/05 & 1/06 CHUG Meetings	Peach Bottom Unit 3 -BWR	Through wall leak in RCIC Steam Supply Drain line to condenser. Location on CS section of line (running through the off gas pipe tunnel) which was not replaced with Cr-Mo P-11 material. The remainder of the line was previously replaced with P11. Event stresses importance of complete line replacements. A review of VYs combined HPCI/RCIC drains as shown on Drawing VYI-HPCI/RCIC Drain Rev.1 and page 15 of JO file 89-0060 shows a carbon steel stub piece at the condenser was left in the line. <b>Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB05)</b>
6/05 CHUG Meeting PER	Wolf Creek - PWR	Pinhole leak in body of 2 inch MS drain line check valve due to erosion from leak-by through upstream steam trap. Thinning was found in 2" tee downstream of steam trap. At VY, piping downstream of MS steam traps has been previously inspected. Given expected increases in flow from EPU, piping DS of ST-60-3 will be inspected in RFO26 (Small Bore Inspection 07-SB02)
8/17/05 CHUG PER 1/06	Hope Creek - BWR	Through wall leak in 1-1/2" line from Steam Seal Evaporator Drain Tank to #3 FDW Htr. Temporary welded clamshell used for repair. Plant documentation indicated line was Cr-Mo P11 material. Lab analysis of metal fillings indicates piping was carbon steel. No equivalent line at VY. However, note the installed material / documentation issue.
8/24/05 Presented at 1/06 CHUG Meeting	LaSalle Unit 1	Through wall leak in RCIC Steam Supply Pot Drain line to main condenser. Leak on straight section of pipe 11 ft D.S. of SW elbow. Major portion of line was replaced with Cr-Mo P-22 material. However this section running through a wall penetration was not replaced by field. Plant documentation indicated that the line was completely replaced. Event stresses importance of complete line replacements. Similar situation to peach Bottom leak presented at 6/05 CHUG meeting. A review of VYs combined HPCI/RCIC drains as shown on Drawing VYI-HPCI/RCIC Drain Rev.1 and page 15 of JO file 89-0060 shows a carbon steel stub piece at the condenser was left in the line. <b>Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB05 at condenser Nozzle 56)</b> Also, a similar situation exists at the previous replacement of 2"MSD-406 (Steam Leads Drains) at the condenser. <b>Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB04 at condenser Nozzle 35)</b>
9/14/05	Waterford 3 -PWR	OE21577: Pinhole leak in carbon steel drain line from Main Steam drip pot. Un isolable from the steam generator. Cause attributed to external corrosion, NOT FAC. Waterford has no turbine building and the MS drain piping is exposed to the weather. All steam process piping at VY is indoors. External corrosion is not a significant concern.
9/15/05 (1/06 CHUG Meeting PER)	Byron Unit 2 -PWR	Through wall leak in No.7 (highest) HP FDW Heater vent line to condenser. 2" schedule 80 line. Previous RT on elbows near FDW Heaters did not identify FAC wear. Location of wear in lines was toward the condenser. At VY all HP FDW Htr. vent lines were replaced with Cr-Mo in RFO24. <b>No further actions for this OE.</b>
9/23/05. 1/06 CHUG Meeting	Cooper -BWR	OE21586: Fatigue failure of 1-1/4" turbine stop drain piping inside condenser. Caused loss of condenser vacuum and manual scram. Lines were previously replaced in January 2005 due to external erosion from the steam space. Inadequate pipe supports and recent change out of LP turbines attributed as causes. RFO25 inspection at VY indicates piping has supports and some external surface wear is occurring. Markings on fittings indicate P-11 material is installed. This indicates previous replacements at VY. <b>Keep OE listed for future reference (Also reference: OE20044-Calvert Cliffs-1/05, OE20032-Palisades-1/05, OE20112-Oconee-1/05, OE19961-Turkey Point-12/04, OE13108-St. Lucie-9/01, OE12609-Byron-3/01, and OE12601-Hatch-10/00.)</b>

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**SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG. - continued**

Date	Plant - Type	Description & Recommended Actions at VY
9/21/05 CHUG PER 1/06	Nilo Mile Pt. 1 - BWR	Through wall leak in 1" GE supplied turbine Bypass Valve 2 <sup>nd</sup> stage leakoff line 2SLBPV line to SSH. Leak location at bend in 1" line off BPV. Similar layout to VY. VY has replaced the entire 1SLBPV line with Cr-Mo in RFO25. Previous FAC inspections on common 2-1/2" header to SSH line. No inspections in 1" lines. Schedule inspection of most probable BPV leakoff lines (1 to 10) based on ranking and consequences of failure in Small Bore Database.
11/15/05 CHUG PER 1/06	Peach Bottom 3 - BWR	Through wall leak in 1" schedule 160 Main Steam Leads drain downstream of orifice to condenser. Leak repair clamp installed. Equivalent piping at VY 2"MSD-406 Steam Leads Drains replaced with Cr-Mo steel except for piping stub at condenser. <b>Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB04 at condenser Nozzle 35)</b>
11/1/05 CHUG PER 1/06	Susquehanna Unit 1 - BWR	Through wall leak in 2" fabricated coupling in Steam Seal Evaporator Drain at Feedwater Nozzle (SSE drains to #2 FW Htr). Attached piping was replaced with Cr-Mo. However, nozzle fitting was never replaced. No equivalent line at VY.
1/06 CHUG Meeting	Diablo Canyon - PWR	Trough wall leak in 2 inch MSR LP Vent Condenser Drain line. Plant documentation indicated that all the lines were replaced with Cr-Mo material. Inspections subsequent to the leak found 6 pieces of carbon steel (not Cr-Mo) during the pipe replacements. <u>Only found through in-situ alloy sampling.</u> Plant includes alloy sampling in their large bore piping FAC inspections. Apparent Cause indicates problem with plant QA (replacements were part of a large fixed price contract). To date at VY, reviews of previous piping replacements have found no such discrepancies. This information should be factored into the evaluation whether or not alloy sampling should be incorporated into the VY FAC program.

**SD: Components subjected to off normal flow conditions, as indicated from the turbine performance monitoring system (Systems Engineering Group).**

The Systems Engineering Production Variance Report for January 1 to January 31, 2006 lists LCV-103-3B as having seat leakage to the condenser. Extraction Steam piping small bore valve is LCV-101-3B is a drain back to the condenser. Piping downstream of the valve on line 5-ES-10B is Cr-Mo steel and is resistant to FAC. The piping was previously inspected in 1993 (Inspection No. 93-SB27) and in 1998 (Inspection No. 98-SB09). No further actions will be performed for RFO26.

Since startup from 2005 (RFO25), no other small bore valves and no steam traps have been identified (to date) using the Turbine Performance Monitoring (TPM) system. However, if new data indicates leaking valves then, additions to the outage scope may be required.

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**LH: Components "De-Scoped" (inspections deferred) from Previous Outages**

This is a new category. Planned inspections had never been deferred at VY before RFO25.

Inspection	Component	Evaluation / Reasons for Recommendation
2005-24 2005-25 2005-26 2005-27 2005-28 2005-29 2005-30 2005-31	1SSH3EL05 1SSH3SP06US 1SSH4EL01 1SSH4SP02US 1SSH5EL01 1SSH5SP02US 1SSH6EL08 1SSH6SP08US	Planned inspections on the turbine Steam Seal header (SSH) and the Steam Packing Exhauster (SPE) lines to determine the extent of condition for CR-VTY-2004-02985 CA 03 were "de-scoped" from the 2005 RFO due to higher priority LP turbine work in the same location.  Inspect these locations during RFO26 in Spring 2007.
2005-32 2005-33 2005-34 2005-35	2SPE3EL01 2SPE3SP01US 2SPE5EL01 2SPE5SP01US	Planned inspections on the turbine Steam Seal header (SSH) and the Steam Packing Exhauster (SPE) lines to determine the extent of condition for CR-VTY-2004-02985 CA 03 were "de-scoped" from the 2005 RFO due to higher priority LP turbine work in the same location.  Inspect these locations during RFO26 in Spring 2007.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**Small Bore Piping**

**SE: Engineering judgment**

Look at piping DS of orifices based on BWR OE

Condensate: Given the 8/04 Mihama event: consider additional component in the condensate system for inspection downstream of flow orifices & venturies.

FE-102-6 and downstream pipe on 2 1/2" C-43 venturi type (TB heater bay elev. 230+/- Given low operating temperatures and upstream of oxygen injection point, scope out and evaluate for inspection in R27 in 2008

Main Steam Drains: Concerns with increased Moisture Carryover under EPU operating conditions: Inspect SSB components with may experience increase flow from EPU

Component	SSB DataBase Number	Location	Reasons/ Comments
1" & 2-1/2" Pipe & Fittings D.S. of Steam Trap ST-60-3	002	Rx Bldg. off Torus Catwalk - West	EPU concerns with increased Moisture carryover. Note this is part of AST ALT Boundary. Last inspected in 1993.
1" & 2-1/2" Pipe & Fittings D.S. LVC -2-143 of Steam Trap ST-60-3	003	Rx Bldg. off Torus Catwalk - West	EPU concerns with increased Moisture carryover. Note this is part of AST ALT Boundary. Last inspected in 1993.
2" CS pipe stub at Condenser wall on line 2"- MSD-406 at condenser nozzle 35 (Steam Lead Drains)	308	Turb. Bldg. Heater Bay. Condenser A -North	EPU concerns with increased Moisture carryover. Also, recent industry experience OE with leaks in CS components in lines with partial material replacements.
2" CS pipe stub at Condenser wall on line 2"- HPCI/RCIC Drain line at condenser nozzle 56	33	Turb. Bldg. Heater Bay. Condenser B Northeast	Recent industry experience OE with leaks in CS components in lines with partial material replacements.

**SG:** Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

See LG above. The EMPAC search performed in LG above is applicable to both Large bore and Small bore components.

**SH:** Components "De-Scoped" (Inspections deferred) from Previous Outages

None

### Feedwater Heater Shells

No feedwater heater shell inspections will be performed during the 2007 RFO. All 10 of the feedwater heater shells have been replaced with FAC resistant materials.

#### **Recent / Relevant Industry OE Regarding Feedwater Heater Shells.**

Date	Plant - Type	Description & Recommended Actions at VY
1/24/04	LaSalle Unit 1, BWR	OE18381/OE17919: Through indication indications in #2 LP feedwater heater extraction steam inlet nozzles. Carbon steel nozzles with Cr-Mo upstream piping. Similar situation existed at VY prior to replacement of all feedwater heater shells with FAC resistant materials. No new actions required at VY.
4/14/25	Browns Ferry 2 -BWR	OE20797: Higher wear rates than expected found in carbon steel Extraction Steam Inlet nozzles on No.3 LP feedwater heaters. Upstream pipe had been replaced with Cr-Mo and C.S. weld build-up had been performed on nozzles. Also a 105% power uprate increased flows. VY has Cr-Mo. ES piping with either Cr-Mo Nozzles or S.S. nozzles. No further actions are required for this OE.
7/28/05 Presented at 1/06 CHUG Meeting	LaSalle Unit 1, BWR	OE:21384: Through Wall Leak in #3 LP feedwater heater shell. Htrs were scheduled for inspection at next RFO. Ranked as lowest priority due to high ES steam quality. Through wall erosion primarily caused by heater design with common axial location for HD inlet and outlet, and to ES inlet nozzles. Through wall leak determined to be result of weld defect (porosity) aggravated by FAC and leading edge effect.

**VY Piping FAC Inspection Program, PP 7028 - 2007 Refueling Outage  
Inspection Location Worksheets / Methods and Reasons for Component Selection**

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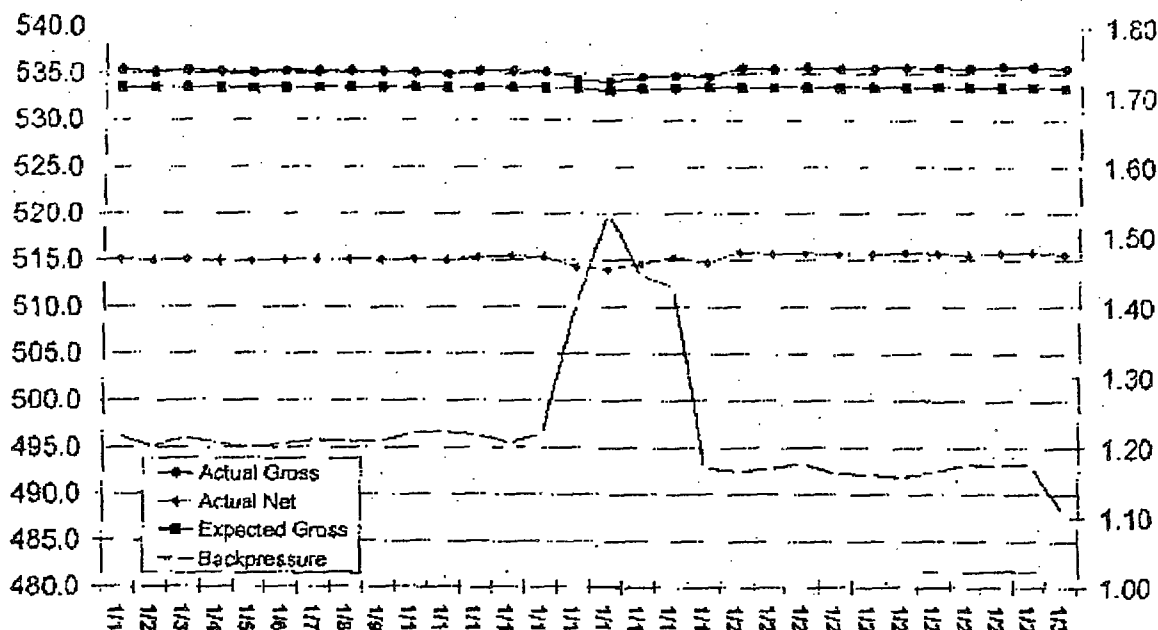
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8. VY-RPT-06-00002, DRAFT, "Vermont Yankee Piping Flow Accelerated Corrosion Inspection Program (PP 7028) 2005 Refueling Outage Inspection Report (RFO 25 - Fall 2005)"
9. VYPPF 7102.01 RFO25 Scope Deletion of Restoration of TM 2004-031 (WO 04-4884-06), dated 10/24/05.
10. VYPPF 7102.01 RFO25 Scope Deletion of FAC Inspections 2005-24 to 2005-35 (WO 04-4983-000/010), dated 11/1/05.

**SYSTEM ENGINEERING  
PRODUCTION VARIANCE REPORT**

Vy 2007 07048  
RFO26  
SCOPIWH  
WORK SHEET

Actual vs. Expected Production January 1 to January 31, 2006



**EVENTS**

Date	Loss	Event
1/16/06	1 MWe/hr	Recirc Gate open to de-ice intake bay

**Full Power Averages For Previous Four Weeks**

- Actual Gross 535.3, Expected Gross 533.5, Net 515.2, Condenser Back Press: 1.22"HGA, Circ Water Inlet: 38° F, Average Difference in Heat Balance to actual: ~ 1.8 MWe (Gain)

**Known Losses (MWe per hour)**

Loss	Tracking Item
Operation < 1593	~ 0.1 N/A
Actual Operation < Indicated Operation	~ 0.7 ER 04-1187
LCV-101-3B Seat Leakage	~ 0.13 WO 05-4597
Main Steam Bypass Valves 1,5 & 7	~ 0.85 PM due in RFO26

**System Engineering Observations and Recommendations:**

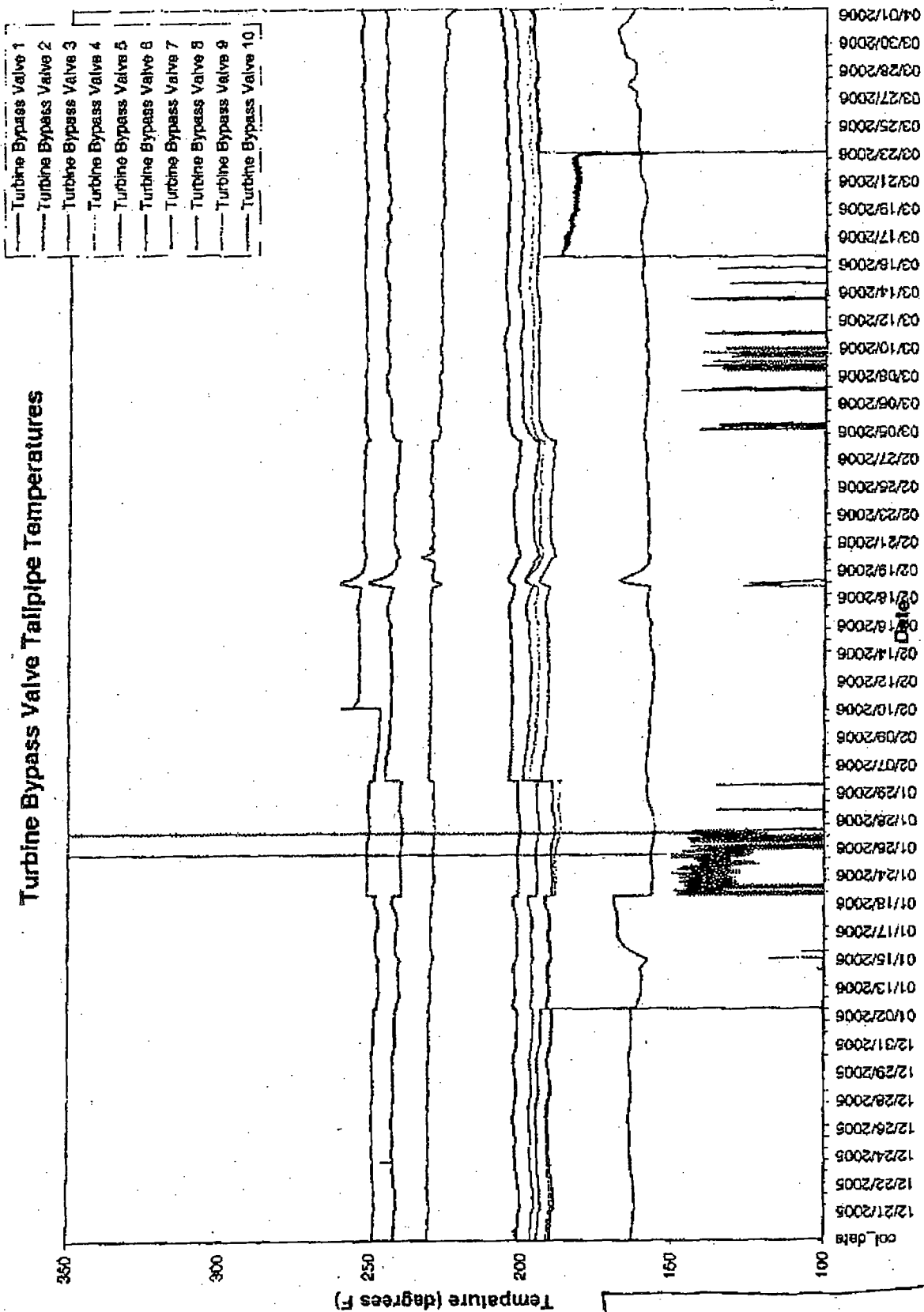
- High Circ Water traveling screen dp's resulted because of ice and debris flushed into the river from the heavy rains this weekend. The Control Room needed to open the Recirc Gate to de-ice the intake bay to address this. As a result, the Condenser is operating at a higher backpressure and net generation is down by approximately 1 MWe. This will not be categorized as a loss per the PI's because it is caused by environmental conditions beyond plant managements control.
- Lower backpressure was achieved on 1/31/06 by throttling open the SJAE suction valves, PCV-OG-516A/B. Opening these valves during EPU summer operation may provide for lower backpressure.
- Cycle Isolation has been restarted. A blown fuse was found, presumably as a result of the UPS-2A restart. The work order is being left open to troubleshoot several computer points that are not indicating properly.

**Thermal Performance Work Status**

- Performed Heater Bay Thermography walkdown of un-instrumented high energy line valves to inspect for leaks during the 2/2/06 downpower. All valves inspected holding tight.

Vy FAX PROGRAM RPO26 (2007) FAX  
 SCOPING WORKSHEETS.

PRK





## Kewaunee 3Q/2006 Plant Inspection Findings

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### Initiating Events

**Significance:**  Jun 23, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

#### **Procedure for Reactor Startup Not Followed**

The inspectors identified a finding associated with a non-cited violation of Technical Specification 6.8.a (written procedures and administrative policies). The finding was for the licensee's failure to follow approved procedures during a plant startup. The finding was of very low safety significance and there were three examples of the finding. The first example of a failure to follow approved procedures occurred when operators incorrectly marked a procedure step as not applicable and failed to execute the step. The second example of the failure to follow approved procedures occurred when operators executed procedure steps out of sequence. The third example occurred during the previous reactor startup conducted in November 2005 when operators performed procedure steps out of sequence in the same manner as executed during this plant startup. Corrective actions included placing Procedure N-0-01 on administrative hold until appropriate procedure changes could be made and training operating crews on procedure adherence.

This finding was of more than minor safety significance. Failure to comply with reactivity management requirements can lead to an uncontrolled reactivity event. In this particular event, the failure to follow the procedural sequence could have resulted in shutdown margin being less than that required by Technical Specifications. However, this finding is of very low significance because the actual shutdown margin did not go below the minimum required by Technical Specifications. This finding affected the cross-cutting issue of human performance.

Inspection Report# : [2006011\(pdf\)](#)

**Significance:**  Jun 23, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

#### **Inadequate Procedure for Reactor Startup**

The inspectors identified a finding associated with an non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," of very low safety significance associated with an event. The inspectors identified that Procedure N-0-01, "Plant Startup from Cold Shutdown Condition to Hot Shutdown Condition," Revision BI, Step 4.45 was inadequate to start up the reactor for the conditions that existed on May 17, 2006. The procedure, as written, would have required the operators to dilute the reactor to a lower boron concentration than the Estimated Critical Position boron concentration prior to withdrawing the Shutdown Bank rods. Corrective actions to address this finding included placing Procedure N-0-01 on administrative hold until appropriate procedure changes could be implemented.

This finding was more than minor in safety significance because this issue, if left uncorrected, would have resulted in the core reactivity shutdown margin being less than that required by Technical Specifications. However, this finding is of very low significance because the procedure step was not executed and shutdown was never below that required by Technical Specifications. This finding affected the cross-cutting issue of human performance.

Inspection Report# : [2006011\(pdf\)](#)

**Significance:**  May 19, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

#### **Criterion XVI: Failed to Identify Causes and Corrective Actions to Preclude Repetition for Significant Conditions Adverse to Quality**

The NRC inspectors identified a finding of very low safety significance that involved a violation of 10 CFR Part 50,

pendix B, Criterion XVI, "Corrective Actions." Specifically, for the turbine building flooding and auxiliary feedwater entrainment performance deficiencies, which were significant conditions adverse to quality, the licensee failed to notify the causes, and to determine corrective actions to preclude repetition.

The finding was greater than minor because the failure to identify the cause and corrective actions to preclude repetition of significant conditions adverse to quality, which led to a degraded cornerstone could result in the NRC needing to take more significant action. The finding was determined to be of very low safety significance based on management review, and the determination that no additional instances of significant conditions adverse to quality have actually occurred due to the failure to identify the causes and corrective actions for the previous performance deficiencies. The cause of the finding was related to the evaluation aspect of the cross-cutting element of problem identification and resolution.

Inspection Report# : 2006007(pdf)

**Significance:**  May 05, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

**Failure to Incorporate Operating Experience Into Preventive Maintenance Procedures**

The inspectors identified a finding associated with a non-cited violation (NCV) of 10 CFR 50.65 (the Maintenance Rule), giving very low safety significance for the licensee's failure to incorporate into station procedures available internal and external operating experience pertaining to 4.16-kilovolt (kV) switchgear mechanically operated contact (MOC) switch linkage assemblies. As a result, preventive maintenance procedures for 4.16-kV safety- and nonsafety-related switchgear breaker cubicles were inadequate and had not been upgraded to incorporate important MOC switch linkage measurements and adjustments to be used during periodic breaker/cubicle maintenance. The licensee entered the problem with the procedures into its corrective action program for resolution. Corrective action included the revision of the procedures to incorporate the need to inspect the linkage and adjust it to within specified values.

The finding is greater than minor because it is associated with the procedure adequacy attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operation. The finding was determined to be of very low safety significance because the transient initiator contributor is a reactor trip that did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The cause of the finding is related to the cross-cutting element of problem identification and resolution.

Inspection Report# : 2006010(pdf)

**Significance:**  Mar 31, 2006

Identified By: NRC

Item Type: FIN Finding

**Failure to Control Loose Materials Within the Protected Area in Response to Adverse Weather Conditions**

This finding of very low safety significance was identified by the inspectors for the licensee's failure to control loose materials within the protected area south of the transformer bays in response to adverse weather conditions. The material could have been blown into the transformers and initiate a transient. The primary cause of this finding was related to the cross-cutting area of problem identification and resolution for the failure to implement effective corrective actions in response to a similar, previous inspection finding (Inspection Report 05000305/2005008). No violation of regulatory requirements occurred.

The licensee entered this issue into its corrective action program and removed the loose material from the transformer bays.

The finding is more than minor because, if left uncorrected, the loose items would become a more significant safety concern by becoming missile hazards; thereby, increasing the likelihood of an initiating event. Additionally, the inspectors determined that this issue was associated with the procedure quality attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations because the station procedure used to control potential airborne material was too narrow in scope. The finding was of very low safety significance because the inspectors answered "no" to all the screening questions in the Significance Determination Process Phase 1 Screening Worksheet under the Initiating Events column.

Inspection Report# : [2006002\(pdf\)](#)**Significance:**  Mar 30, 2006

Identified By: NRC

Item Type: FIN Finding

**Failure to Adequately Evaluate an Inoperative Indicating Lamp for a Turbine control Valve**

A finding of very low safety significance was identified by the inspectors for the failure to adequately evaluate an inoperative indicating lamp associated with the turbine control valves. The primary cause of this finding was attributed to the cross-cutting area of human performance because procedures were available, but not followed, that would have facilitated proper performance of the task.

The licensee entered this item into its corrective action program and reviewed open work orders, provided a status update to management, and increased communications of related expectations.

The finding is greater than minor because the failure to adequately evaluate deficient conditions, if left uncorrected, would become a more significant safety concern. The finding was of very low safety significance because the inspectors answered "no" to all the questions in the Significance Determination Process Phase 1 Screening Worksheet under the Initiating Events column.

Inspection Report# : [2006002\(pdf\)](#)**Significance:**  Dec 31, 2005

Identified By: NRC

Item Type: NCV NonCited Violation

**Inadequate Startup Procedure Resulted in an Inadvertent Carbon-Dioxide Fire Suppression Discharge and Declaration of a Notice of Unusual Event**

nding of very low safety significance was self-revealed during two events when use of an inadequate plant prestartup procedure resulted in actuation of the CARDOX Carbon Dioxide system. A Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified for the failure to include adequate acceptance criteria in Procedure N-0-02-CLA, "Plant Prestartup Checklist". The primary cause of this finding was related to the resource attribute in the cross-cutting area of Human Performance. The licensee failed to provide the operators with quality procedures containing criteria to know when the secondary plant was appropriately aligned.

The inspectors determined that the finding was greater than minor because it involved the configuration control, human performance, and procedure quality attributes of the Initiating Events Cornerstone. Additionally the finding affected the cornerstone objective of limiting the likelihood of those events that upset plant stability during power operations. Specifically, an incorrect lineup could exist in the secondary system resulting in an initiating event, or an unanalyzed secondary system response after a trip. The issue was of very low safety significance because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. Corrective actions taken by the licensee include procedural enhancements to ensure that systems are lined up properly before continuing with plant startup.

Inspection Report# : [2005017\(pdf\)](#)

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## Mitigating Systems

**Significance:**  Sep 30, 2006

Identified By: NRC

Item Type: FIN Finding

**Technical Specification LCO not Entered for diesel Generators Inoperable while in Refueling Shutdown**Inspection Report# : [2006004\(pdf\)](#)

**Significance:**  Jun 30, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

**Reactor Protection System Surveillance Procedure Revised Without Proper Review**

The inspectors identified a finding of very low safety significance and an associated non-cited violation of Technical Specification 6.8, "Procedures," during a review of a procedure. The licensee had changed the procedure to allow the turbine-driven auxiliary feedwater (TDAFW) pump to be considered available for risk management purposes while the trip control switch was in pull-to-lock during the performance of the surveillance procedure; however, the required Plant Operating Review Committee review and approval for the change was not obtained. Corrective actions, to date, included review of the surveillance procedure by the Plant Operating Review Committee and inclusion into the procedure of additional provisions to ensure availability of the TDAFW pump while the control switch is in pull-to-lock during performance of the procedure. The cause of this finding is related to the cross-cutting area of human performance because the licensee's failure to follow a plant procedure regarding the review and approval of safety-related procedures.

The finding is greater than minor because if left uncorrected the finding would become a more significant safety concern. Specifically, improper application of the temporary procedure change process could lead to a more significant unreviewed, proper procedure change. Additionally, this issue is associated with the procedure quality attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems to respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the failure to provide adequate review and approval of a safety-related surveillance procedure prior to issuance for use and the failure to include adequate provisions to ensure availability of a safety-related component in the surveillance procedure potentially impacted equipment availability. The finding is of very low safety significance because the answer to all the screening questions in the significance determination process Phase 1 screening worksheet in the Mitigating Systems column was "no".  
Inspection Report# : [2006003\(pdf\)](#)

**Significance:**  Jun 30, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

**Leak Developed in Service Water Pipe after Wall Thinning Evaluation was Cancelled**

The self-revealed finding of very low safety significance and an associated non-cited violation of 10 CFR Part 50, Appendix C, Criterion XVI, "Corrective Action," were identified on April 25, 2006, when a leak due to pipe-wall thinning was identified in a 90° elbow in a service water (SW) line to the 'B' emergency diesel generator. This wall-thinning and leak, a condition adverse to quality, resulted in the need to declare the emergency diesel generator inoperable and a shut down of the reactor to allow repair of the leak. In April 2004, a work order to inspect the elbow for wall-thinning was cancelled after wall thickness in a nearby elbow was evaluated by the licensee and deemed acceptable. The extrapolation of inspection results from one elbow to the other elbow was inappropriate. Corrective actions taken by the licensee included replacement of the failed section of SW piping, performance of additional inspections on SW piping, and replacement of other safety-related sections of SW piping. The cause of this finding is related to the cross-cutting area of problem identification and solution because the licensee failed to promptly identify an issue potentially impacting safety-related piping.

The finding is greater than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems to respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the failure to conduct wall-thinning evaluation in April 2004 resulted in the need to take the emergency diesel generator out-of-service and shut down the reactor to allow repair of the pipe. Additionally, the failure to inspect and correct, as necessary, wall-thinning in a safety-related system, if left uncorrected, would become a more significant safety concern through the possible development of a large system leak or the complication of the operations of a safety-related system. The finding is of very low safety significance because the answer to all the screening questions in the significance determination process Phase 1 screening worksheet in the Mitigating Systems column was "no".  
Inspection Report# : [2006003\(pdf\)](#)

**Significance:**  May 19, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

**Criterion V: Failed to Incorporate Appropriate Acceptance Criteria for Assessing Operability of the AFW Pump**

The NRC inspectors identified a finding of very low safety significance that involved a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Specifically, the licensee failed to incorporate appropriate acceptance criteria for assessing operability of the auxiliary feedwater pump following identification of a piping obstruction.

The finding was greater than minor because the finding was associated with the Mitigating Systems cornerstone attribute of procedure quality which affected the cornerstone objective. Specifically, the relevant procedure was not adequate to ensure the availability, reliability, and capability of the auxiliary feedwater system to respond to initiating events. The finding was determined to be of very low safety significance because subsequent evaluation of the pipe occlusions, using appropriate acceptance criteria, supported past operability of the pump. The cause of the finding was related to the evaluation aspect of the cross-cutting element of problem identification and resolution.

Inspection Report# : [2006007\(pdf\)](#)

**Significance:**  May 19, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

**Criterion III: Failed to Correctly Translate Containment Sump Volume into Design**

The NRC inspectors identified a finding of very low safety significance that involved a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." Specifically, the licensee failed to ensure that design basis calculations correctly translated the containment sump volume at the time of the switch over from the refueling water storage tank to the containment sump to ensure adequate available net positive suction head and vortex suppression for the residual heat removal pumps.

The finding was greater than minor because the finding was associated with the Mitigating Systems cornerstone attribute of design control and affected the cornerstone objective because the inadequate calculation impacted the design requirements the new containment strainers being installed to resolve Generic Safety Issue 191. The finding was determined to be of very low safety significance because (1) the licensee normally kept the refueling water storage tank at a level above the Technical Specification minimum; (2) new strainers were not yet installed; and (3) inspector-independent calculations indicated that the pumps had adequate net positive suction head and vortex suppression, with the additional non-conservatisms incorporated. The cause of the finding was related to the corrective action aspect of the cross-cutting element of problem identification and resolution.

Inspection Report# : [2006007\(pdf\)](#)

**Significance:**  May 19, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

**Criterion III: Failed to Verify or Check the Adequacy of the Design Canceling Design Change Request 2548**

The NRC inspectors identified a finding of very low safety significance that involved a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." Specifically, the licensee failed to properly evaluate the minimum flow requirements of the high head safety injection pumps.

The finding was greater than minor because the finding was associated with the Mitigating Systems cornerstone attribute of design control and affected the cornerstone objective as providing inadequate minimum flow to the SI pumps could result in the pumps failing under certain accident scenarios. The finding was determined to be of very low safety significance because both the licensee and the inspectors determined that the safety injection pumps remained operable with the 47 gpm minimum flow rate. The cause of the finding was related to the corrective action of the cross-cutting element of problem identification and resolution.

Inspection Report# : [2006007\(pdf\)](#)

**Significance:**  May 05, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

**Failure to maintain cable separation for cables 1N15010 and 1N15012 associated with train 'B' of ICCMS**

The inspectors identified a finding associated with a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," that pertained to a modification that failed to incorporate applicable design requirements for cable separation. Nonsafety-related cables associated with train 'B' reactor coolant pump (RCP) safety-related cable trays and cables were bundled inside the RCP breaker cubicles with train 'A' RCP safety-related cables feeding the reactor protection system (RPS). Consequently, a fault in the train 'B' cable/cable tray could propagate to train 'A'. The licensee entered the problem into its corrective action program for resolution. Corrective actions included encasing the nonsafety-related cables in flexible metal conduit and confirming that other safety-related cables were not affected.

The finding is greater than minor because it was associated with the design control attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding was determined to be of very low safety significance because of the redundancy and coincident logic in the RPS design; and it did not represent a loss of system safety function, an actual loss of safety function of a single train, an actual loss of safety function of one or more non-technical specification trains of equipment, designated as risk significant per 10 CFR 50.65, for greater than 24 hours, and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event.  
Inspection Report# : [2006010\(pdf\)](#)

Significance:  Mar 31, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

**Ineffective Corrective Actions to Resolve Boric Acid Leakage from the 1A RHR Pump Flange Studs and Nuts**

This finding of very low safety significance and an associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion I, "Corrective Action," was identified by the inspectors for ineffective identification and the initiation of corrective actions to resolve boric acid leakage from the 1A residual heat removal (RHR) pump flange studs and nuts. The primary cause of this finding was attributed to the cross-cutting area of problem identification and resolution. During a review of corrective actions associated with the licensee's identification of a moderate amount of boric acid around various pump flange studs and nuts, the inspectors found that numerous prior occasions existed where the licensee had identified similar conditions yet failed to adequately identify and initiate actions to evaluate or correct this condition adverse to quality.

The licensee entered this item into its corrective action program and wrote a work order to replace the pump casing flange gasket.

The finding is greater than minor because it is associated with the equipment performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Additionally, failure to correct a condition adverse to quality in a safety-related system, if left uncorrected, would become a more significant safety concern. The finding was of very low safety significance because the inspectors answered "no" to all the screening questions in the Significance Determination Process Phase 1 Screening Worksheet under the Mitigating Systems column.  
Inspection Report# : [2006002\(pdf\)](#)

Significance:  Mar 31, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

**Failure to Apply Appropriate Quality Classification to TSC Diesel Generator Modifications as Required by Procedures**

This finding of very low safety significance and an associated non-cited violation of the Kewaunee Technical Specifications, Section 6.8, "Procedures," was identified by the inspectors during a review of plant modification Design Change Request 90, which replaced the existing Technical Support Center diesel generator fuel oil day tank level switches with new level switches of a different design. The inspectors determined that, in accordance with procedure GNP-01.01.01, "Determination of Nuclear Safety Designed Classifications, QA [Quality Assurance] Type and EQ [Environmental Qualification] Type," the new level switches should have been designated as "Augmented Quality." Contrary to this, the new switches were not designated as augmented quality. The primary cause of this finding was attributed to the cross-cutting area of problem identification and resolution because of the licensee's failure to take effective corrective actions for previously identified problems with its quality assurance program.

The licensee entered this item into its corrective action program and conducted supplemental audits of quality-designated equipment, added additional related elements to an upcoming quality assurance group audit of the quality assurance program, and the conduct of a cause evaluation of related issues.

The finding is greater than minor because it is associated with the design control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Additionally, failure to comply with the provisions of nuclear safety-related procedures, if left uncorrected, would become a more significant safety concern. The finding is of very low safety significance because the inspectors answered "no" to all the screening questions in the Significance Determination Process Phase 1 Screening Worksheet under the Mitigating Systems column.

Inspection Report# : [2006002\(pdf\)](#)

Significance:  Mar 30, 2006

Identified By: NRC

Item Type: FIN Finding

**Failure to Adequately Evaluate the Extent-of-Condition of Degraded Fuses in Installed Equipment**

A finding of very low safety significance was identified by the inspectors for the failure to adequately evaluate the extent-of-condition relative to installed equipment for a 10 CFR Part 21 notification for degraded Bussmann® fuses. The primary cause of the finding was attributed to the cross-cutting area of human performance because procedures were available, but not followed, that would have facilitated proper performance of the task.

The licensee entered this item into its corrective action program and planned to review other installed fuses and to conduct an evaluation of original problem.

The finding was greater than minor because the failure to adequately evaluate the impact of potentially degraded safety-related fuses on installed equipment, if left uncorrected, would become a significant safety concern. Specifically, the condition could cause premature circuit interruptions of safety-related or risk significant mitigating components, when called upon to perform the related functions, and this is an undesirable condition. The finding was of very low safety significance because the inspectors answered "no" to all the screening questions in the Significance Determination Process Phase 1 Screening Worksheet under the Mitigating Systems column.

Inspection Report# : [2006002\(pdf\)](#)

Significance:  Dec 31, 2005

Identified By: NRC

Item Type: NCV NonCited Violation

**Adjustments Performed on Safety-Related Service Water Valve 4B Without Procedure Resulted in Valve Being Declared Inoperable**

On October 5, 2005, a finding of very low safety significance was self-revealed when SW-4B failed to meet its In-Service Testing stroke time requirements during the performance of Surveillance Procedure SP-02-138B and an associated unplanned entry into a Technical Specification Limiting Condition for Operation occurred. The condition occurred because the licensee made adjustments to safety-related Valve SW-4B, "Turbine Building Service Water Train "B" Header Isolation," without procedural guidance to perform such adjustments. The primary cause of this finding was related to the personal attribute of the cross-cutting area of human performance because maintenance was performed without required procedures.

The finding was more than minor because performing adjustment of safety-related equipment without procedural guidance, if left uncorrected, would become a more significant safety concern. Additionally, the finding is associated with the Reactor Safety/Mitigating Systems Cornerstone attribute of Procedure Quality and effects the associated Cornerstone objective of insuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable sequences. Using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Operations," the inspectors answered "no" to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. Therefore, this finding was of very low safety significance. A Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified for the failure to provide procedural guidance for adjusting SW-4B; a safety-related valve which could affect the ability of safety-related mitigating system components to perform their intended function. Corrective actions taken by the licensee include procedural revisions to

ngthen guidance on adjustment of safety-related components.

Inspection Report# : [2005017\(pdf\)](#)

**Significance:**  Dec 31, 2005

Identified By: NRC

Item Type: NCV NonCited Violation

**Operator Licensing Exam Results Were Less Than Minimum Acceptable Percentage For Passing**

A finding of very low safety significance was identified. The finding was associated with unsatisfactory operating crew performance on the simulator during facility-administered licensed annual operator requalification examinations. Of the 7 crews evaluated, 2 did not pass their annual operating tests. The finding is of very low safety significance because the failures occurred during testing of the operators on the simulator, because there were no actual consequences to the failures, and because the crews were removed from watch-standing duties, retrained, and re-evaluated before they were authorized return to control room watches.

Inspection Report# : [2005017\(pdf\)](#)

**Significance:**  Dec 16, 2005

Identified By: NRC

Item Type: FIN Finding

**Trending of Adverse Conditions Identified During Outages**

The inspectors identified a finding of very low safety significance for the licensee not reviewing corrective action program documents (CAPs) during outages for potential trends of conditions adverse to quality. As part of the screening process of CAPs, the licensee assigned, as possible, CAPs to various "hot buttons." Hot buttons were searchable categories in the corrective action program computer system that had been established for various problems, such as equipment tagging errors, security door control, and reactivity management. For non-outage times, the licensee assigned a monthly number of CAPs for each hot button that, if exceeded for 3 months in succession, would result in the generation of a CAP to investigate possible trend. However, as of December 16, 2005, the licensee did not use hot button action levels during outages when the number of CAPs written was much higher than during non-outage times.

This finding is greater than minor because if left uncorrected would become a more significant safety concern. This finding is not suitable for Significance Determination Process evaluation, but has been reviewed by NRC management and is determined to be a finding of very low safety significance. No violation of regulatory requirements occurred. The cause of the finding is related to the cross-cutting element of problem identification and resolution, because of not identifying potential conditions adverse to quality through trending of CAPs during outages.

Inspection Report# : [2005005\(pdf\)](#)

**Significance:**  Dec 16, 2005

Identified By: NRC

Item Type: NCV NonCited Violation

**Failure to Correct Procedure Non-Adherence**

The inspectors identified a finding of very low safety significance and a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to take corrective action for procedure non-compliance identified during the licensee's 2004 self-assessment of the corrective action program. As a result of the assessment, CAP025194, "Corrective Action Program Procedure and Guidance Document Use," was written and documented that plant workers are not following corrective action program procedures for apparent cause evaluations and root cause evaluations, effectiveness review content, priority and due date assignments, initiator feedback, and documentation of corrective action completion. To correct this problem, corrective action CA018094, "Corrective Action Program Procedure and Guidance Document Use," was written and specified one or 2 weeks of requiring "in-hand" use by the plant staff of the corrective action program administrative procedure. However, completion of this action was delayed several times and on July 25, 2005, CAP025194 and CA018094 were closed with the only documented action taken being a July 18, 2005, meeting of the station human performance steering committee at which the licensee decided not to take action because of the pending transition to the corrective action program documents of the plant's new owner.

This finding is greater than minor because if left uncorrected would become a more significant safety concern. This finding is not suitable for Significance Determination Process evaluation, but has been reviewed by NRC management and is



determined to be a finding of very low safety significance. The cause of the finding is related to the cross-cutting element of problem identification and resolution, because of the failure to take corrective action for non-adherence to station procedures.

Inspection Report# : 2005005(pdf)

**Significance:**  Dec 16, 2005

Identified By: NRC

Item Type: NCV NonCited Violation

**Failure to Adequately Correct Residual Heat Removal Pump Seal Leakage**

A finding of very low safety significance that was a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified for the licensee's ineffective corrective action to repair a leak on the seal of the "B" residual heat removal (RHR) pump. The leak was identified on November 2, 2005, when the pump was stopped following the performance of a required surveillance. The leak rate exceeded leakage control program limits. A similar leak was identified on June 16, 2004, for which the licensee replaced the seal in November 2004.

This finding is greater than minor because it was associated with the "RCS (reactor coolant system) equipment and barrier performance" attribute of the barrier integrity cornerstone and does affect the cornerstone objective of providing reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accidents or events. Although the RCS barrier was affected, the finding did not affect the mitigation capability of the RHR system and did not contribute to the likelihood of a primary or secondary system loss of coolant accident initiator or affect the containment integrity. Therefore, the finding is of very low safety significance.

Inspection Report# : 2005005(pdf)

**Significance:**  Oct 06, 2005

Identified By: NRC

Item Type: VIO Violation

**Potential Flooding in the Turbine Building Basement**

A review of design drawings by the inspectors revealed a direct piping connection from the turbine building sump to the trench in safeguards alley. The inspectors determined that there were no check valves located in the piping to prevent water spills in the turbine building basement from backing up into the safeguards alley. The inspectors also noted that no flood barriers specifically designed to protect equipment in the safeguards alley from flooding in the turbine building basement were installed. The inspectors requested additional information from the licensee regarding potential flooding events occurring in the safeguards alley. The licensee documented its response to the inspectors' information request in Condition Evaluation (CE) 014653. This CE stated that it would take approximately 3 hours for flooding caused by AFW pump discharge to affect safety-related equipment, and such flooding could be mitigated by opening doors between the safeguards alley and the turbine building basement. The CE also stated that other sources of flooding in the turbine building basement need not be considered since such flooding events are outside the design basis of the plant.

The inspectors identified a finding that was preliminarily determined to be of substantial to high safety significance because the licensee failed to provide adequate design control to ensure that Class I equipment was protected against damage from the rupture of a pipe or tank resulting in serious flooding or excessive steam release to the extent that the Class I equipment's function is impaired. Specifically, the design of Kewaunee Power Station (KPS) did not ensure that the auxiliary feedwater (AFW) pumps, the 480-volt (V) safeguards buses, the safe shutdown panel, emergency diesel generators (EDGs) 1A and 1B, and 4160-V safeguards buses 1-5 and 1-6 would be protected from random or seismically induced failures of non-Class I systems in the turbine building. The finding is also an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for not ensuring that the design of KPS prevented turbine building flooding from impacting multiple safety related equipment trains needed for safe shutdown of the plant. The inspectors determined that a primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution, because there was an earlier opportunity to discover and correct this issue based on the licensee's 2003 experience when minor flooding from the turbine building had challenged safety equipment located adjacent to the turbine building basement.

The finding was more than minor because it impacted Mitigating Systems cornerstone attributes of design control (initial design and plant modifications) and protection against external factors (internal flood hazards and seismic events) and it impacted the Mitigating Systems cornerstone objective to ensure availability, reliability and capability of multiple trains of safety related equipment to respond to events to prevent core damage. A Significance Determination Process Phase 3 risk

lysis determined that this finding was preliminarily of substantial to high safety significance. The licensee has taken significant corrective actions, including extensive system and structural modifications to address this issue.

After considering the information developed during the inspection, and the additional information you provided prior to, during, and in response to our questions at the Regulatory Conference, the NRC has concluded the inspection finding is appropriately characterized as Yellow (i.e., an issue with substantial importance to safety, that will result in additional NRC action and potentially other NRC action).

Inspection Report# : [2004009\(pdf\)](#)

Inspection Report# : [2005002\(pdf\)](#)

Inspection Report# : [2005011\(pdf\)](#)

Inspection Report# : [2005018\(pdf\)](#)

Inspection Report# : [2006015\(pdf\)](#)

**Significance:** **W** Aug 16, 2005

Identified By: NRC

Violation Type: VIO Violation

#### **Potential Common Mode Failure of Auxiliary Feedwater**

NUREG-05000305/2005002-05 is associated with the design of the AFW pump's discharge pressure switches. The inspectors identified the potential for air intrusion into operating AFW pumps, potentially resulting in a common mode failure of the AFW system. This could occur during certain events where the suction source is lost prior to being able to manually swap source of water from the CST to the SW system.

The inspectors identified a finding that was preliminarily determined to be of low to moderate safety significance, because Kewaunee failed to provide adequate design control to ensure the AFW pumps would be protected from failure due to air intrusion during tornado or seismic events; as well as from failure during potential runout conditions. The finding is also an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for not effectively providing controls to check the adequacy of the design for protecting the AFW pumps during design and license basis events.

The finding was determined to be more than minor since it impacted Mitigating System cornerstone attributes of design control (initial design and plant modifications) and the cornerstone objective to ensure availability, reliability, and capability of the AFW system to respond to events to prevent core damage. A Significance Determination Process Phase 3 analysis determined that this finding was preliminarily of low to moderate safety significance. The licensee has taken significant corrective actions, including extensive modifications to the system.

After considering the information developed during the inspection, the NRC has concluded the inspection finding is appropriately characterized as White (i.e., an issue with low to moderate increased importance to safety, which may require additional NRC inspections).

Inspection Report# : [2006015\(pdf\)](#)

Inspection Report# : [2005002\(pdf\)](#)

Inspection Report# : [2005010\(pdf\)](#)

Inspection Report# : [2005014\(pdf\)](#)

## **Barrier Integrity**

**Significance:** **G** May 19, 2006

Identified By: NRC

Violation Type: NCV NonCited Violation

#### **Criterion III: Failed to Properly Translate the ICS Design Basis into the Technical Specifications**

The NRC inspectors identified a finding of very low safety significance that involved a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." Specifically, the licensee failed to ensure that design basis calculations correctly translated the internal containment spray flow requirements into the Technical Specification allowed number of blocked internal containment spray nozzles.

The finding was greater than minor because the containment spray system could have been inoperable with the allowable spray degradation and allowable number of blocked containment spray nozzles. The finding was determined to be of very low safety significance because the internal containment spray system was determined to be operable. The cause of the finding was related to the evaluation aspect of the cross-cutting element of problem identification and resolution.  
Inspection Report# : [2006007\(pdf\)](#)

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## Emergency Preparedness

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## Occupational Radiation Safety

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### Public Radiation Safety

**Significance:**  Jun 30, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

**Failure to Properly Calibrate the Waste Discharge Liquid and the Steam Generator Blowdown Radiation Monitors**  
The inspectors identified a finding of very low safety significance and an associated violation of NRC requirements for the failure to comply with technical specification and Offsite Dose Calculation Manual (ODCM) requirements in the calibration of two liquid discharge radiation monitors listed in the ODCM. Specifically, the radiation monitor high alarm trip functions were not verified with radiation sources during instrument calibration.

The finding is greater than minor because it is associated with the plant facilities/equipment and instrumentation attribute of the Public Radiation Safety cornerstone and affected the cornerstone objective of ensuring adequate protection of public health and safety from exposure to radioactive materials released into the public domain. Specifically, not verifying the proper operation of a radiation monitor at its high alarm trip setpoint could result in the use of a monitor that does not properly operate at the high alarm setpoint and the consequent unintended release of radioactive material to the environment in excess of regulatory limits. The finding is of very low safety significance because actual effluent discharges were adequately analyzed for radioactive content by the licensee prior to release, and the licensee's ability to assess dose from radioactive waste (radwaste) liquid discharges was not impaired, nor were regulatory dose limits or As-Low-As-Is-Reasonably-Achievable dose constraints exceeded due to liquid effluent discharges.

Inspection Report# : [2006003\(pdf\)](#)

**Significance:**  Mar 30, 2006

Identified By: NRC

Item Type: NCV NonCited Violation

**Failure to Adequately Evaluate Degraded Flow Conditions on a SW System Radiation Monitor**

A finding of very low safety significance and an associated non-cited violation of the Kewaunee Technical Specifications, Section 6.8, "Procedures," was identified by the inspectors for the failure to adequately evaluate degraded flow in a service water system radiation monitor. The primary cause of this finding was attributed to the cross-cutting area of human performance because procedures were available, but not followed, that would have facilitated proper performance of the

k.

The licensee entered this item into its corrective action program and planned to conduct inspections of other radiation monitor sample chambers, assess the need for an in-line filter, and assess the need for a modification to correct the recurring problem with the service water radiation monitor.

e finding was greater than minor because the finding involved conditions contrary to those required by the offsite dose culation manual. Specifically, sampling requirements that were required to be initiated when the related radiation monitoring instrumentation should have been declared inoperable were not accomplished. The finding was of very low ety significance because no radiological releases were possible from the indicated pathways when the condition existed.  
pection Report# : 2006002(pdf)

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## Physical Protection

Physical Protection information not publicly available.

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## Miscellaneous

st modified : December 21, 2006



Union of Concerned Scientists  
Citizens and Scientists for Environmental Solutions

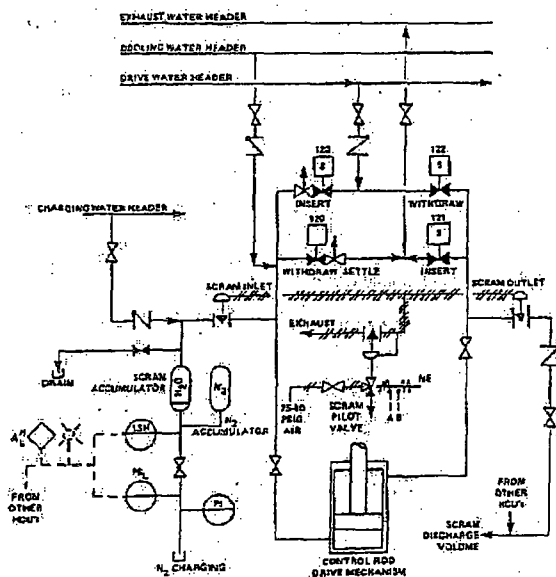
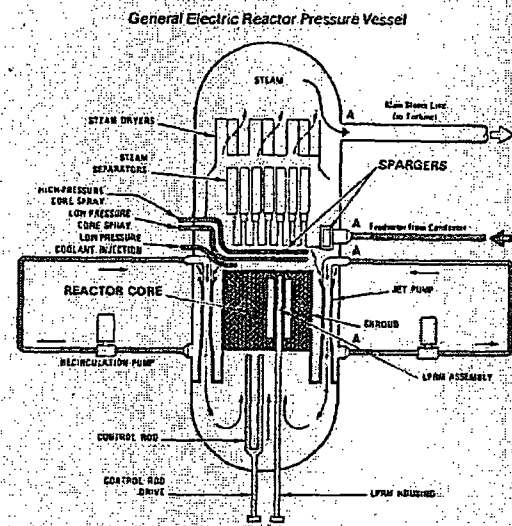
# issue brief

## CONTROL ROD PROBLEM AT COOPER

At 2:12 am on the morning of Saturday, May 19, 2007, operators at the Cooper nuclear plant in Nebraska manually scrammed the reactor from approximately 50 percent power due to a leak of cooling water from the reactor vessel that forced the reactor building to be evacuated because of high airborne radioactivity levels. For some unexplained reason, no emergency was declared for this loss of coolant accident resulting in evacuation of workers from harm's way and shut down of the plant.

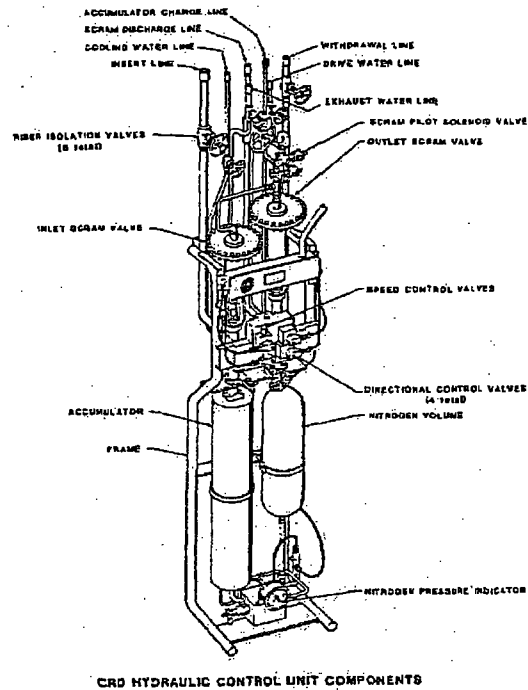
The Cooper nuclear plant features a boiling water reactor (BWR) supplied by the General Electrical Company. Late Friday evening, operators at Cooper reduced the reactor power level to approximately 50 percent to conduct planned maintenance activities. One of the two recirculation pumps was removed from service so workers could repair its motor. One of the feedwater pumps was removed from service for repairs to its lubricating oil system. And three of the reactor's 137 control rods were fully inserted and disabled to replace their directional control valves.

As shown in the graphic, control rods enter the BWR reactor core from below. The control rods function as brakes for the nuclear engine. Withdrawing control rods allows the nuclear reactor to increase power. Inserting control rods reduces the reactor's power and can stop it completely.



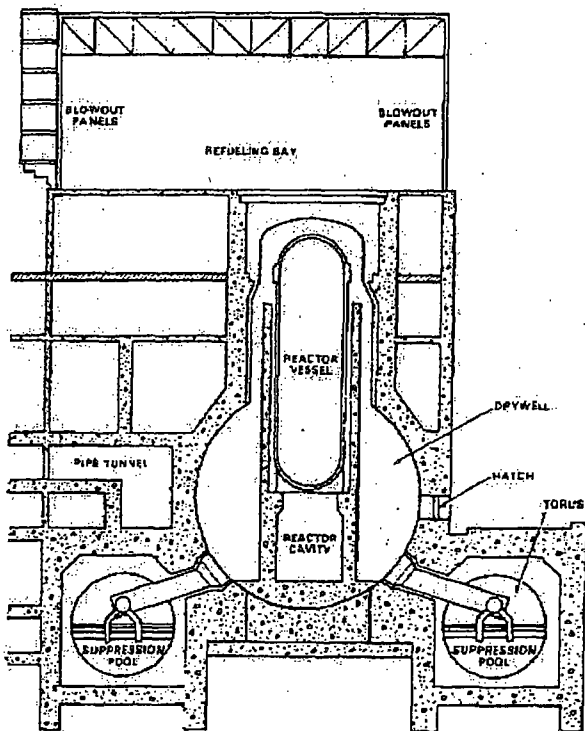
Each of the 137 control rods at Cooper is a hydraulic piston. Water pressure is used to move the control rod. Water is supplied below the control rod piston and vented from above it in order to insert the control rod into the reactor core. Conversely, water is supplied above the piston and vented from below in order to withdraw the control rod. Four directional control valves (numbered 120, 121, 122, and 123 in the schematic) sequence open and closed to insert and withdraw a control rod under normal operation. To rapidly shut down (called 'scram') the reactor, the scram inlet and scram outlet valves open to apply maximum differential pressure across the piston to cause it to fully insert within 5 seconds.

In order to safely replace the four directional control valves on each of the three control rods, workers fully inserted the control rods and then manually closed the isolation valves (shown as the vertical "bow-ties" in the schematic between the directional control valves and the control rod drive mechanism at bottom center). Workers reported a small amount of water leaking from the withdraw directional control valve (numbered 122) for control rod 26-27. The water was coming from the reactor vessel getting past the closed isolation valves and leaking from directional control valve 122. The four directional control valves, including 122, appear in the mid-section of the control rod drive hydraulic control unit shown on the right. The leak got bigger until a steam plume was visible. (The water inside the reactor vessel is maintained under nearly 1,000 pounds per square inch pressure. When it leaks into the atmospheric pressure of the reactor building, it flashes to steam like the plume from a teapot.) Reactor water leaking from the valve contained radioactivity and created an airborne radiation hazard. The control room supervisor ordered the reactor building to be evacuated as a precaution.



CRD HYDRAULIC CONTROL UNIT COMPONENTS

The unisolable leak of radioactive reactor cooling water into the reactor building prompted the operators to manually shut down the reactor. The leak rate was far less than the makeup capacity of the plant's emergency systems. But the leak wasn't going to fix itself and could not be tolerated.



At this time, it's not apparent why the operators did not declare an emergency condition. The NRC has a four-tiered emergency classification system: Unusual Event, Alert, Site Area Emergency and General Emergency in increasing order of severity. This event involved a leak of reactor cooling water that could not be isolated (i.e., the manual isolation valves had already been closed and yet the leak produced a visible steam plume) that was outside of the primary containment structure (i.e., the leak was outside of the drywell and torus which comprise the primary containment structure and was inside the reactor building which is part of the less-robust secondary containment structure). A cooling water barrier and a containment barrier had been compromised, but not even an Unusual Event was declared for this unusual event. The NRC should look into why an emergency declaration was not made for this event.

May 21, 2007


Page 3 of 3

Prepared by: David Lochbaum  
Director, Nuclear Safety Project

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## Event Notification Report for June 21, 2007

### Nuclear Reactors

### Nuclear Materials

### Radioactive Waste

### Nuclear Security

### Public Meetings

### & Involvement

U.S. Nuclear Regulatory Commission  
Operations Center

Event Reports For  
06/20/2007 - 06/21/2007

\*\* EVENT NUMBERS \*\*

43427 43433 43435 43436

General Information or Other	Event Number: 43427
Rep Org: FLORIDA BUREAU OF RADIATION CONTROL Licensee: NODARSE AND ASSOCIATES Region: 1 City: WEST PALM BEACH State: FL County: License #: 2429-1 Agreement: Y Docket: NRC Notified By: STEVE L FURNACE HQ OPS Officer: STEVE SANDIN	Notification Date: 06/18/2007 Notification Time: 12:17 [ET] Event Date: 02/18/2007 Event Time: 12:00 [EDT] Last Update Date: 06/18/2007
Emergency Class: NON EMERGENCY 10 CFR Section: AGREEMENT STATE	Person (Organization): WILLIAM COOK (R1) GREG MORELL (FSME)

### Event Text

#### AN AGREEMENT STATE REPORT FROM THE STATE OF FLORIDA - DAMAGED TROXLER GAUGE

This event was called in by the State of Florida Bureau of Radiation Control:

"Troloxler Gauge damaged on site February 22, 2007. Company RSO notified this office on June 18, 2007. Back loader drove over gauge and damaged it. Gauge leak tested by Atlantic Drilling and found to be satisfactory."

Incident Location: Fort Lauderdale, Davie Blvd between 31st and 32 streets.

Isotope(s)/Activities: Cs-137 (10 mCi) and Am-241/Be (40 mCi)

State of Florida Incident Number: FL07-100

Power Reactor	Event Number: 43433
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ility: CLINTON ion: 3 State: IL : [1] [ ] [ ] Type: [1] GE-6 : Notified By: JIM PETERSON OPS Officer: JOHN MacKINNON	Notification Date: 06/20/2007 Notification Time: 16:35 [ET] Event Date: 06/20/2007 Event Time: 13:55 [CDT] Last Update Date: 06/20/2007
ergency Class: NON EMERGENCY CFR Section: 72(b)(3)(xiii) - LOSS COMM/ASMT/RESPONSE	Person (Organization): JAMNES CAMERON (R3)

nit	SCRAM Code	RX CRIT	Initial PWR	Initial RX Mode	Current PWR	Current RX Mode
1	N	Y	1	Startup	1	Startup

it Text

OR LOSS OF EMERGENCY ASSESSMENT CAPABILITY - 13 OF 44 EMERGENCY SIRENS OUT OF SERVICE  June 20, 2007, a disturbance on the transmission system was experienced causing a loss of 13 of 44 emergency ns (approximately 30 percent) for Clinton Power Station. At 1355 hours (CDT), since power was not restored to e sirens within one hour, this event was determined to be a major loss of emergency assessment capability. At 2 hours, only 6 sirens (14 percent) remain out of service. At this time, an estimated return to service has not n provided for the remaining sirens."  Witt County, Illinois Emergency Management Agency, and the NRC Resident have been informed of this information. "
--

er Reactor  ility: SAN ONOFRE ion: 4 State: CA : [ ] [2] [ ] Type: [1] W-3-LP,[2] CE,[3] CE : Notified By: JOEL BARNETT OPS Officer: PETE SNYDER	Event Number: 43435  Notification Date: 06/21/2007 Notification Time: 03:24 [ET] Event Date: 06/20/2007 Event Time: 22:50 [PDT] Last Update Date: 06/21/2007
ergency Class: NON EMERGENCY CFR Section: 72(b)(2)(iv)(B) - RPS ACTUATION - CRITICAL 72(b)(3)(iv)(A) - VALID SPECIF SYS ACTUATION	Person (Organization): BLAIR SPITZBERG (R4)

nit	SCRAM Code	RX CRIT	Initial PWR	Initial RX Mode	Current PWR	Current RX Mode
2	M/R	Y	96	Power Operation	0	Hot Standby

it Text

LED INSTRUMENT AIR HEADER LEADS TO MANUAL REACTOR TRIP  1250 on 6/20/07, "Instrument Air header pressure failed at a brazed joint. The loss of Instrument Air pressure caused Steam Generator (S/G) Feedwater Regulating Valves to stop controlling and S/G level, E-088, to rise onrolled. Control Room Operators tripped the reactor manually. Main Feedwater Pumps were manually tripped to excess feedwater to the S/Gs. Loss of Instrument Air failed the normal cooling to Containment. Containment ergency Cooling units were manually started to provide containment cooling. The standard post trip actions were id out with all safety functions satisfied." The site is proceeding with post trip recovery. The Instrument Air leak isolated at 2321 PDT.  control rods fully inserted on the manual trip. RCPs are in operation transferring decay heat to the S/Gs. ergency feedwater is feeding the S/Gs with steam being discharged to the condenser via the steam dumps. ospheric relief valves were used to discharge steam to the atmosphere initially for approximately 20 minutes owing the trip. There are no primary to secondary tube leaks. Containment isolation failed closed as expected owing the loss of instrument air pressure to the containment.  mal offsite power is available and the emergency diesel generators are available if needed.  licensee notified the NRC Resident Inspector.
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TOP

ver Reactor	Event Number: 43436
Facility: LIMERICK Region: 1 State: PA Unit: [ ] [2] [ ] RX Type: [1] GE-4, [2] GE-4 NRC Notified By: NED DENNIN HQ OPS Officer: JOE O'HARA	Notification Date: 06/21/2007 Notification Time: 04:05 [ET] Event Date: 06/21/2007 Event Time: 03:15 [EDT] Last Update Date: 06/21/2007
Emergency Class: NON EMERGENCY 10 CFR Section: 50.72(b)(3)(v)(D) - ACCIDENT MITIGATION	Person (Organization): WILLIAM COOK (R1)

Unit	SCRAM Code	RX CRIT	Initial PWR	Initial RX Mode	Current PWR	Current RX Mode
2	N	Y	100	Power Operation	100	Power Operation

## Event Text

## HPCI INOPERABLE DUE TO QUARTERLY VALVE STROKE TEST FAILURE

"During performance of the quarterly HPCI valve stroke test the HV-55-2F006, HPCI pump discharge isolation valve to Core Spray failed to open within the maximum allowed time. The HV-55-2F006 valve is a motor operated valve and the maximum allowed opening time is 17.25 seconds. The valve was given an open signal via the handswitch as required by the test but did not initially respond. Several minutes later the valve went full open. HPCI was declared inoperable at 0315 on 6/21/2007. Cause for valve stroke time failure is not known at this time."

As a result, the licensee is in a 14 day shutdown LCO.

The licensee notified the NRC Resident Inspector.

Privacy Policy | Site Disclaimer  
Thursday, June 21, 2007

April 15, 2003

EA-03-053

Mr. John T. Conway  
Vice President Nine Mile Point  
Nine Mile Point Nuclear Station, LLC  
P.O. Box 63  
Lycoming, NY 13093

SUBJECT: NINE MILE POINT NUCLEAR STATION - NRC SPECIAL INSPECTION  
REPORT 50-220/03-003 - PRELIMINARY WHITE FINDING

Dear Mr. Conway:

On March 7, 2003, the NRC completed a special inspection of the Nine Mile Point Nuclear Station, Unit 1. The enclosed report documents the inspection findings which were discussed at the completion of the inspection with you and other members of your staff during an exit meeting on March 7, 2003.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The team reviewed selected procedures and records, observed activities, and interviewed personnel. In particular, the inspection reviewed event evaluations, including technical analyses, root cause investigation, relevant performance history, and extent of condition to assess the significance and potential consequences of the degraded condition of the reactor building closed loop cooling (RBCLC) system.

This report discusses a finding that appears to have low to moderate safety significance. As described in Section 4OA3 of this report, this finding involves inadequate implementation of corrective actions for significantly degraded piping in the RBCLC system. There were numerous prior opportunities to identify and correct this problem. This finding was assessed using the reactor safety Significance Determination Process (SDP) as a potentially safety significant finding that was preliminarily determined to be White (i.e., a finding with some increased importance to safety, which may require additional NRC inspection). The finding has low to moderate safety significance because a pipe rupture in the RBCLC system could result in an initiating event and loss of certain equipment necessary to mitigate plant transients and accidents.

Following identification of the degraded piping, you implemented appropriate corrective actions by replacing most of the RBCLC system piping located in the drywell with improved hardware and design. With these compensatory measures in place while long term corrective actions are being developed, our inspectors determined that an immediate safety hazard does not exist.

The finding also appears to be an apparent violation of NRC requirements and is being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600. The current Enforcement Policy is included on the NRC's Website at <http://www.nrc.gov/what-we-do/regulatory/enforcement.html>.

We believe that we have sufficient information to make our final risk determination for the performance issue regarding inadequate corrective action for the degraded RBCLC system. However, before the NRC makes a final decision on this matter, we are providing you an opportunity to either submit a written response or to request a Regulatory Conference where you would be able to provide your perspectives on the significance of the finding, the bases for your position, and whether you agree with the apparent violation. If you choose to request a Regulatory Conference, we encourage you to submit your evaluation and any differences with the NRC evaluation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. The NRC will also issue a press release to announce the Regulatory Conference.

Please contact Mr. James M. Trapp at (610) 337-5186, within 10 business days of the date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at <http://www.nrc.gov/reading-rm/adams.html> (the Public Electronic Reading Room).

If you have any questions, please contact Mr. Trapp at (610) 337-5186.

Sincerely,

/RA/

Wayne D. Lanning, Director  
Division of Reactor Safety

Docket No. 50-220  
License No. DPR-63

Enclosures: 1) Inspection Report 50-220/03-003 w/Attachment: Supplemental Information  
2) NRC Special Inspection Team Charter

John T. Conway

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cc w/encl:

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**ENCLOSURE 1**

**U.S. NUCLEAR REGULATORY COMMISSION  
REGION I**

**Docket No:** 50-220

**License No:** DPR-63

**Report No:** 50-220/03-003

**Licensee:** Nine Mile Point Nuclear Station, LLC (NMPNS)

**Facility:** Nine Mile Point, Unit 1

**Location:** P. O. Box 63  
Lycoming, NY 13093

**Dates:** February 10, 2003 - March 7, 2003

**Inspectors:** S. Pindale, Senior Reactor Inspector (Team Leader)  
S. Chaudhary, Reactor Inspector  
E. Cobey, Senior Reactor Analyst  
E. Knutson, Resident Inspector

**Approved by:** James M. Trapp, Chief  
Projects Branch 1  
Division of Reactor Projects

## SUMMARY OF FINDINGS

IR 05000220/2003-003; 02/10/2003 - 03/08/2003; Nine Mile Point, Unit 1; Special Inspection Team of Degraded Piping in the Reactor Building Closed Loop Cooling System.

The inspection was conducted by two regional inspectors, one resident inspector, and one regional senior reactor analyst. One preliminary White finding was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

### A. Inspector Identified and Self-Revealing Findings

Cornerstones: Initiating Events and Mitigating Systems

- **Preliminary White.** An apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was identified by the team associated with the failure to evaluate significant conditions adverse to quality involving degraded piping in the reactor building closed loop cooling (RBCLC) system. The failure to adequately identify and evaluate equipment problems, and correct deficiencies, resulted in repetitive and continued degraded piping conditions in the RBCLC system. Specifically, a RBCLC system piping leak occurred on May 15, 2002, due to significant pipe corrosion, primarily as a result of inadequate piping design, application and operation. Additionally, numerous RBCLC system leaks occurred during several preceding years. However, the cause for these leaks was not determined and appropriate corrective actions were not implemented. This led to further degradation of the RBCLC system piping such that additional significant leaks occurred on December 5, 2002, and again on December 12, 2002. These significant leaks in December 2002 were accompanied by a significant reduction in the pipe wall which degraded the structural integrity of the affected piping sections.

This finding has low to moderate safety significance, based on the results of the phase three SDP analysis, because the degraded RBCLC piping resulted in an increase in the likelihood of the loss of the RBCLC system due to piping failure, which directly affected the initiating events cornerstone. The loss of the RBCLC system would also result in the loss of cooling to several other risk significant systems (e.g., feedwater/condensate pumps, recirculation pumps, shutdown cooling heat exchangers, etc.) following a loss of coolant accident or a loss of all AC power event where AC power is recovered prior to core damage, which directly affected the mitigating systems cornerstone. (Section 40A3.4; AV 50-220/03-03-01)



## REPORT DETAILS

### Summary of Plant Status

The reactor building closed loop cooling (RBCLC) system provides cooling for various reactor auxiliary equipment, as well as balance of plant equipment. Major components supplied by the system included the drywell air coolers, reactor recirculation pump coolers, reactor building equipment drain tank cooler, fuel pool heat exchangers, shutdown cooling system, control room air conditioning equipment, instrument air compressors, and the high pressure injection system (i.e., feedwater pumps, feedwater booster pumps, and condensate pumps). The RBCLC system is a safety-related, risk-significant system that is required to operate during normal plant operations and accident conditions.

In May 2002, and again on December 5 and 12, 2002, the licensee experienced substantial leaks in RBCLC small bore (less than 2" diameter) piping. Following evaluation and analysis of these leaks, the licensee discovered notable and widespread wall thinning in RBCLC piping sections, which were most severe at threaded mechanical connections (where piping thickness was the smallest due to the thread roots). This reduction in wall thickness was ultimately attributed to a combination of general corrosion, flow-assisted corrosion, and galvanic corrosion.

Prior to 2002, there had been numerous additional small bore piping leaks within the RBCLC system at threaded mechanical joints. Repair methods for these leaks varied, and included tightening the connection or fittings, replacing components (such as flow switches), seal welding the threaded connections, and replacing affected pipe sections. Around May 2000, chloride and sulfate concentrations in the RBCLC system were found to be elevated. Near the same time, RBCLC system oxygen levels were found to be significantly below normal levels, and iron particulate levels were high. These parameters indicated an increased corrosion rate, however, efforts to identify the cause and correct the abnormal chemistry parameters were unsuccessful.

The NRC team's review of the event details determined the root and contributing causes for the degraded RBCLC piping included: inadequate system design, inadequate corrective actions, and degraded RBCLC system water chemistry. Subsequent to the December 12, 2002, leak, several immediate corrective actions were implemented, including extensive RBCLC small bore piping and fitting replacement with improved piping material and design. Longer term similar actions were also in progress for the remaining RBCLC piping sections that had not been replaced. In addition, the licensee was continuing their efforts to determine the cause and corrective actions for the unexpected and unexplained chemistry parameters.

The performance deficiency was the failure, prior to December 12, 2002, to determine the cause of a significant condition adverse to quality and implement appropriate corrective actions to prevent further degradation of the RBCLC system. The NRC team determined that the licensee's structural analysis did not provide evidence that the as-found condition of the degraded piping in the RBCLC system retained sufficient strength, and consequently, the structural integrity of the affected RBCLC system piping may not have been maintained when subjected to design loading conditions. The safety significance of the inspection finding, based on the increase in core damage frequency due to internal and external initiating events, was determined to be White, which represents a finding of low to moderate safety significance.

#### 4. OTHER ACTIVITIES (OA)

##### 4OA3 Event Followup

##### 1. Degraded RBCLC Piping Due to Corrosion

##### a. Inspection Scope

This inspection was conducted in accordance with NRC Inspection Procedure 93812, "Special Inspection," to assess the licensee's actions associated with the December 5 and 12, 2002, discovery of two instances where portions of the RBCLC piping were significantly corroded such that leaks occurred in the system. The licensee conducted event evaluations following each incident to determine the root cause and corrective actions. The team reviewed the associated design basis documents, calculations, and other related documents. A list of the documents reviewed by the team is provided as Attachment 1 to this report.

The team reviewed aspects of the historical performance of the RBCLC system relative to prior leaks and associated licensee actions and evaluations. The team also examined portions of degraded RBCLC piping that had been removed from the system, walked down portions of the system, and interviewed licensee personnel.

##### Chronology of System Leakage

The RBCLC system piping was designed and installed in accordance with the B31.1-1955 Code for Pressure Piping. The pipe was Schedule 40 carbon steel and threaded connections were used for many of the small bore piping connections. The nominal wall thickness for 1-1/2 inch diameter Schedule 40 and 80 pipe is 0.145 and 0.200 inches, respectively. The use of threaded connections reduces the nominal wall thickness as the threads are cut into the pipe, thereby further reducing the pipe wall thickness at the root of the threads. In addition, the system also contained several dissimilar metal joints (e.g., carbon steel to stainless steel; and carbon steel to bronze) at several of the piping connections. While this was not prohibited by the piping design code, direct connection (without insulating barriers) of dissimilar metals can lead to galvanic corrosion.

The team reviewed documentation of RBCLC system leaks dating back to 1991. In July 1991, the unit was shut down to investigate increased drywell leakage. The source of the leakage was RBCLC from the recirculation pump seal coolers. At that time, a total of seven out of ten recirculation pump seal cooler threaded pipe connections were found to be leaking. These connections consisted of threaded pipe joints, as opposed to welded pipe sections. The licensee attributed the leakage, as documented in deviation event report (DER) 1991-0560, to thermal expansion and vibration which caused the mechanical connections to loosen. The licensee determined the root cause of the event to be an inadequate system design.

In February 1992, DER 1992-0480 documented that the long term corrective actions of DER 1991-0560 had not been implemented. The corrective action in this DER recommended that the long term corrective actions from DER 1991-0560 should be implemented prior to closing DER 1992-0480. Despite continuing issues with recirculation pump seal cooler leaks through the 1990's (as documented in DER 2002-2383), this recommendation was not implemented, and modification N1-80-83 was subsequently canceled in 1994.

In September 2000, two recirculation pump seal cooler leaks were identified and documented in DER 2000-3268. Both leaks were from threaded connections between the RBCLC piping and the coolers. The cause of the leaks (i.e., whether the leakage was through the mechanical joints or through-wall degradation of the piping) was not positively identified. However, the DER noted that attempts to stop the leak by tightening the connections were unsuccessful. Both leaks were repaired by seal welding.

During a mid-cycle outage in May 2002 to investigate drywell leakage, two significant RBCLC leaks were identified in the drywell, as documented in DER 2002-2383. One leak was from a recirculation pump seal cooler mechanical joint. Again, the cause of the leak was not positively identified, although attempts to tighten the joint did not stop the leakage. This leak was repaired by seal welding. The other leak was from the downstream threaded connection to a flow switch in RBCLC piping to the 14 recirculation pump. This leak was repaired by replacing the flow switch and the immediate upstream and downstream piping. Subsequent vendor analysis identified the apparent cause of the flow switch leak as galvanic corrosion of the downstream pipe, due to dissimilar metals in the flow switch and the piping. Flow turbulence downstream of the flow switch continually exposed fresh metal and allowed the galvanic action to progress to failure. Although the results of the vendor analysis results were available in July 2002, they were not factored into the corrective action process and, consequently, were not addressed until after the subsequent RBCLC leaks were identified in December 2002.

On December 5, 2002, Unit 1 shut down to investigate an increase in unidentified drywell leakage. The source was found to be RBCLC system leakage from the threaded joint on the downstream side of the outlet check valve from the 11 drywell equipment drain tank cooler. The apparent cause, as identified in DER 2002-5166, was a combination of galvanic corrosion between dissimilar metal components (bronze check valve, carbon steel piping) and turbulent flow downstream of the check valve. The leak was repaired by eliminating the check valve and replacing the associated piping. Additional actions associated with this DER included the following:

- Eliminating the outlet check valve from the other (12) drywell equipment drain tank cooler;
- Replacing susceptible pipe assemblies at the outlet of the recirculation pump motor and seal cooler lines, and eliminating check valves and dissimilar metal joints;

- Completing seal welding of RBCLC lines to the recirculation pump seal coolers; and
- Replacing flow switches and connecting piping for the two recirculation pumps that had not had this done within the last four years.

One week later, on December 12, 2002, a leak was identified at the RBCLC inlet connection to the 11 drywell cooler heat exchanger. The leak was from the threaded connection of a pipe nipple to a threaded elbow, originating in a pinhole at the root of the exposed portion of the threads. The licensee (DER 2002-5280) identified that the apparent cause for this leak was general corrosion combined with the tapered threads on the original construction Schedule 40 piping. This threaded joint was not a dissimilar metal joint (it was all carbon steel).

In response to the most recent problem, the unit was shut down. The corrective action for this leak was to replace all drywell air cooler inlet and outlet piping. Additional actions associated with DER 2002-5280 included replacement of the majority of RBCLC piping inside the drywell with Schedule 80 piping using welded (rather than threaded) connections. The recirculation pump motor cooler piping was determined to be in good condition and was not replaced; and the upstream piping to the equipment drain tank was determined to be acceptable until the refueling outage scheduled for Fall 2004.

#### RBCLC Chemistry Control

In early 2000, unexplained changes in the RBCLC water chemistry parameters began to occur. Over a period of several months, the dissolved oxygen concentration decreased from its normal value of about 3000 ppb (parts per billion) to essentially zero. Subsequently, in June 2000, DER 2000-2139 was written to document an increase in RBCLC water conductivity, and chloride and sulfate concentrations. Typically, such changes are the result of service water system leakage into the RBCLC system.

Attempts to identify the source of the chloride and sulfate contamination have been unsuccessful to date. Contaminant concentrations have, for the most part, been maintained within specification by performing system feed-and-bleeds (i.e., purging the water volume in the system). The cause for the oxygen depletion has not been determined. The feed-and-bleed evolution used aerated water (oxygen concentration on the order of 3000 ppb), however, the RBCLC oxygen concentration remained approximately zero. This indicated that some process was continuing to consume the dissolved oxygen. The licensee had also identified elevated concentrations of soluble and insoluble iron in the RBCLC water since the year 2000, which was consistent with the oxygen depletion mechanism being the result of corrosion.

## 2. Root and Contributing Causes of Degraded RBCLC Piping

### a. Inspection Scope

The team reviewed the licensee's event evaluation reports and cause analyses associated with the RBCLC system pipe leaks and degraded piping. The team also independently assessed the root and causal factors for the event. The team reviewed data and corrective action program documents, conducted plant tours, and interviewed personnel, including station management.

### b. Findings

The team concluded that the licensee's cause evaluations prior to the December 12, 2002, leak did not effectively evaluate the observed degraded piping. The licensee's actions, subsequent to this leak, have included a comprehensive cause investigation and also an evaluation to determine how the organizational and cultural environment affected previous attempts to correct this problem. The licensee appropriately identified that general corrosion, galvanic cells, and flow-assisted corrosion degraded the RBCLC system integrity and led to the leaks.

The licensee's investigation identified several preliminary findings, including: station personnel did not use effective problem solving techniques; weaknesses in technical rigor/justification; high standards for thorough problem solving were not reinforced; and personnel did not demonstrate judicious use/application of failure analysis examinations.

The NRC team's review of the event details determined the following regarding the root and contributing causes for the degraded RBCLC piping:

- *Inadequate System Design:* The use of threaded (vs. welded) connections with Schedule 40 piping (nominal wall thickness of 0.145") resulted in a thin base material at the piping connections, particularly at the roots of the threads. Dissimilar metals in various system components resulted in galvanic corrosion which, in some cases, accelerated the wall loss of the internal piping surface to the point of loss of adequate structural integrity and through-wall leakage.
- *Inadequate Corrective Actions:* In 1991, DER 1991-0560 identified threaded connections at the recirculation pump seal coolers as a system design deficiency and recommended corrective action to implement a previously identified modification (N1-80-83) to redesign the connections. However, this corrective action was initially not acted upon, as identified by DER 1992-0480, and ultimately was canceled. Corrective actions associated with several of the leaks consisted, in part, of seal welding at the threaded pipe joints. This action was superficial in that it only eliminated the immediate symptom (the leak) and made no attempt to identify the root cause of this significant condition adverse to quality. In addition, the failure analysis for the leaking flow switch, which identified galvanic corrosion and turbulent flow as the cause of failure, was not factored into the corrective action program, and therefore, was not promptly acted upon. Corrective actions associated with the December 5, 2002 leak, while more extensive than in previous cases, were still not adequate to identify

the root cause of the system degradation and to prevent the additional failure, that occurred one week later.

- *Degraded RBCLC System Water Chemistry:* Actions over about two years have been unsuccessful in identifying the source of chloride and sulfate contamination, and the cause for the oxygen depletion. While the cause of these issues remains unknown, they apparently have contributed to accelerated system degradation through corrosion, as evidenced by the coincident increase in soluble/insoluble iron content of the water. Attempts to identify the source of dissolved hydrogen and nitrogen have also been unsuccessful.

While the licensee's recent efforts to identify the root and contributing causes of degraded RBCLC piping were acceptable after the December 12, 2002 leak, some of the causes remained undetermined. In particular, the licensee has not yet been able to identify the source of the abnormal chemistry parameters in the RBCLC system. The licensee's efforts were continuing in this area to identify and diagnose the RBCLC system abnormal chemistry parameters.

### 3. Structural Integrity of RBCLC Degraded Piping

#### a. Inspection Scope

The team interviewed personnel, conducted a partial system walkdown, and reviewed the licensee's engineering evaluations associated with the structural integrity of the as-found condition of the 1-1/2" diameter degraded piping in the RBCLC system to independently assess the condition of the degraded RBCLC system piping. In particular, the team reviewed the licensee's preliminary evaluation of the system structural integrity as documented in engineering report NER-1S-031, Rev. 00A. The licensee evaluated the condition that they determined represented the worst case condition. This evaluation considered the pipe degradation, and RBCLC system static and dynamic loading (including additional loading potentially caused by transients initiating in other systems).

The limiting location was the circumferential ligament adjacent to the section where the December 5, 2002, leak occurred. It was located in the threaded area of the RBCLC piping one thread adjacent to the leak. Engineering report NER-1S-031 documented evaluations pertaining to the following:

- Failure analysis of a section of 1-1/2" diameter pipe installed at the RBCLC return line from the 11 drywell sump cooler (105-04) between check valve CKV-70-362 and ball valve VLV-70-363;

- Collapse load analysis for the above pipe to determine the collapse moment capacities for various temperature conditions and sustained loads (dead weight plus operating loads). The method used in calculating collapsing moment were per Appendix F of ASME Code, Section III;
- Piping analysis for pipe between line No. 105-04 and the 4" diameter header pipe; and
- A comparison of applied moments to the calculated collapsing moment capacities for the applicable loading conditions:
  - Load Case 'a': Dead weight, design pressure 125 psig, normal RBCLC system operating temperature 100°F, and 0.05 maximum ground acceleration for seismic loads.
  - Load Case 'b': Dead weight, design pressure 125 psig, and a drywell temperature of 240°F as a result of a small break loss of coolant accident.
  - Load Case 'c': Dead weight, transient pressure of 142 psig, combined with a drywell temperature of 215°F as a result of a loss of offsite power event.

The results of the piping analysis documented in NER-1S-031 were used as input to an inelastic finite element analysis using the ANSYS Computer Program for the various load conditions. This analysis was used to evaluate the structural integrity of the existing ligament geometry in the threaded piping section.

b. Findings

The licensee determined the collapse moment capacity and the applied moment for each of the three load cases. The collapse moment capacity relates to the calculated strength of the RBCLC piping, based upon material properties. Inherent in the licensee's analysis was that they assumed the remaining material in the measured ligament (after the significant corrosion occurred), retained the properties of the original piping/metal material. The applied moments were calculated for each of the loads that would result in these cases. The analysis assumed that the integrity of the pipe would not be maintained if the applied moment exceeded the collapse moment.

The calculated collapse moment capacities (criteria) and applied moments are summarized in the following table (Note: all units are ft-lbs).

Load Case	Calculated collapse moment capacity (Criterion)	Criterion, including measurement tolerance	Applied moment
a	37.8	36.6	37
b	42	40.7	40
c	42	40.7	38

Although the applied moment exceeded the collapse moment capacity for load case 'a,' the licensee stated that the applied moment was within 1% of the reduced collapse moment capacity (criteria above).

The licensee stated that there was no leak evident at the ligament that was analyzed (downstream of bronze check valve CKV-70-362). They concluded that this location and configuration was a critical section and was the worst case (and bounding) for the purpose of analysis. They also concluded that the critical piping section would retain sufficient structural integrity to prevent collapse of the piping when subjected to the design loading conditions. While the team did not identify a location or configuration that would be more bounding, the team determined the absence of leak was not an indication of structural integrity and/or loading capacity. Further, a leak can be prevented by a barrier that does not have any significant structural capacity.

The team identified several additional concerns associated with the licensee's analysis, assumptions, and methodology. For example, the pipe wall thickness assumed in the finite element analysis was a very thin ligament at the root of the pipe thread, and in some cases, only a few thousandths of an inch. The material behavior in thin ligaments may be significantly different than that assumed in the analysis. Very thin carbon steel material may not exhibit the homogenous isotropic behavior assumed in the licensee's analysis; the grain size of the metal significantly affects the structural properties. The material properties assumed in the analysis was based on the original certified material test report (CMTR) supplied with the piping purchase order.

In addition to the above uncertainties in the material properties, there are potential of negative cumulative errors in wall thickness measurements, i.e. magnification and calibration tolerance/error in the electron microscope, and the caliper or other measuring tools and equipment.

The removed section of the pipe was visually examined by the inspection team to assess the material condition. The removed sections indicated a highly corroded piping section with missing thread root. Even where the material was not missing, a flash light illumination indicated a material ligament so thin that it appeared nearly translucent. The team also learned that a full section of the pipe was able to be broken apart manually following removal by maintenance personnel.

Finally, the team noted that the licensee's analyses and evaluations were based on assumptions that had not been substantiated by test and/or verifiable data. As such, the licensee's results were considered preliminary by the licensee and their consultants.



In summary, although the RBCLC system remained in operation and functional during the operating cycle, the team concluded that the licensee's evaluation did not provide an adequate basis to demonstrate that the piping in the RBCLC system retained sufficient structural strength/integrity when subjected to loading conditions during postulated events. In addition, the team concluded that a passive failure of the degraded RBCLC piping was a dominant failure mode, which resulted in an increased likelihood of a loss of RBCLC initiating event.

#### 4. Corrective Actions

##### a. Inspection Scope

The team interviewed licensee personnel, reviewed related corrective action program documents, and reviewed associated licensee evaluations associated with the degraded piping. The adequacy, extent and timeliness of the licensee's corrective actions were also assessed.

##### b. Findings

##### Corrective Actions Implement for RBCLC Leakage

In December 2002, the licensee identified significant and widespread degradation of the RBCLC system piping due to corrosion. This degradation occurred despite numerous prior opportunities to identify, determine the root causes and correct the condition. Leaks had occurred over the previous several years due to significant degradation of small bore piping (less than 2" diameter), and a failure of this size line would result in failure of the RBCLC system.

The team determined that the leaks that occurred on May 15, 2002, represented an opportunity to recognize the potential significant degradation of the RBCLC system. The more significant of the two leaks occurred at a threaded connection on the downstream side of a flow switch associated with one of the five recirculation pump coolers. The second leak at a threaded mechanical pipe connection associated with another recirculation pump cooler was seal welded. At that time, the licensee attributed those leaks to inherent leakage associated with threaded connections and noted that leaks at the pipe connections for the seal cooling piping to and from the recirculation pumps had been a chronic problem for many years. They failed to adequately evaluate the cause and extent of the degraded condition. Further, the licensee failed to evaluate an associated flow switch failure analysis report (performed by a vendor), which was dated July 29, 2002, and provided relevant insights regarding the nature and extent of the corrosion in the RBCLC system. This failure analysis was not included in the licensee's corrective action process, and therefore, was not adequately reviewed.

The December 5, 2002, leak also represented an opportunity for the licensee to perform a detailed cause analysis and implement comprehensive corrective actions. This leak was located adjacent to the 11 equipment drain cooler discharge check valve. The licensee concluded that the carbon steel pipe was experiencing wall thinning on the downstream side at and near threaded connections to either bronze or austenitic stainless steel components, and that this degradation due to galvanic corrosion was

accelerated due to turbulent flow conditions. The area at the threaded connection that showed the most severe degradation consisted of a very thin ligament of corroded metal. Although the licensee identified several RBCLC pipe areas for further inspection and repair, these actions failed to properly identify and characterize the cause and extent of the degradation mechanism. Specifically, the licensee failed to recognize that general internal pipe corrosion contributed substantially to the pipe wall thinning, and that the inspection scope for susceptible piping areas should have extended beyond dissimilar metal, turbulent flow interfaces.

Soon after the startup from the December 5, 2002, forced outage, another leak occurred on December 12, 2002. The investigation of this leak revealed additional RBCLC piping that was substantially degraded. During the extent of condition evaluation, the licensee again identified wall thinning due to corrosion. However, in this instance, a dissimilar metal and galvanic corrosion mechanism was not present. The licensee had not previously considered that the carbon steel to carbon steel connections may also exhibit significant corrosion. Further, the effect of threads on pipe wall thickness in conjunction with the pipe wall thinning (absent a galvanic mechanism) had not been considered during the previous evaluations.

#### Assessment of Corrective Actions

In evaluating the RBCLC system leak history and associated licensee corrective actions, the team made several observations. In particular, the team determined that the licensee's efforts in response to the problems over the years were focused on fixing symptoms (leaks) rather than identifying causes, determining extent of condition, and implementing effective corrective actions. For example, the team observed the following:

- For the RBCLC system leaks identified in May 2002 and earlier, the apparent causes did not consider mechanisms other than leakage across the threads. DER 2002-2383 stated that it is *expected* that threaded piping connections that are not seal welded will leak over an extended period of time. The cause analysis was not sufficiently rigorous to identify that the Schedule 40 pipe wall thickness at the threaded area was significantly less than the rest of the system. Therefore, the cause analysis, extent of condition assessment and scope of repairs were not sufficient to preclude additional RBCLC leakage.
- Seal welding was proposed and implemented on threaded connections as a housekeeping measure. This activity could potentially stop an active leak as a temporary measure. However, because seal welding is not designed or credited to restore structural integrity, it could also mask significant internal degradation and allow continued internal corrosion to further degrade the structural integrity of the pipe.
- The licensee recognized the degraded chemistry parameters in the RBCLC system (high chloride and sulfate concentration, low oxygen, high iron), existed for over two years, however, the cause of these conditions had not been identified. The licensee's feed-and-bleed activities of the system only temporarily and marginally improved the chemistry conditions.

- In 1980, a modification was initiated to eliminate certain RBCLC threaded connections in the drywell (in particular, threaded joints in recirculation pump coolers to eliminate a possible leakage source). However, the modification was not installed, and was canceled in 1994 based on low priority and continued satisfactory system performance (two successful operating runs).

The team reviewed the licensee's corrective actions following the December 12, 2002 leak (after the licensee fully recognized the cause and extent of condition). Several immediate corrective actions were implemented. These activities included extensive replacement of RBCLC piping and fittings inside the drywell. The majority of RBCLC fittings and pipe (about 90%) was replaced with the more robust schedule 80 piping. The remaining piping was determined to be acceptable through calculations in combination with ultrasonic and visual inspections. Also, the new piping sections were connected by welded joints (except in some cases, where prohibited by physical interference problems).

Longer term similar actions are also in progress for RBCLC piping located outside the drywell. The licensee similarly evaluated the existing condition of the RBCLC piping outside the drywell by ultrasonic and visual inspections, and concluded that there was sufficient pipe wall thickness and structural integrity to support interim continued operation of the RBCLC system. Current licensee plans are to replace all 3" and smaller diameter RBCLC system piping (inside and outside the drywell) with Schedule 80 welded joint piping within two years. The licensee performed testing and conducted an evaluation and determined that the larger than 3" piping was not subject to a similar type of failure mechanism. Regarding the chemistry issues, the licensee has been developing an action plan to identify the source of loss of oxygen (oxygen injection and detection), and the source of the other elevated parameters. The team found the licensee's completed and planned corrective actions to be appropriate.

#### Performance Assessment

The licensee's failure, prior to December 12, 2002, to determine the cause of a significant condition adverse to quality and implement corrective action to prevent repetition, despite prior opportunities to do so, was a performance deficiency. This failure allowed the RBCLC system to continue to degrade due to several factors, including inadequate design and poor system chemistry. The system degraded significantly due to general corrosion, galvanic corrosion, and flow-assisted corrosion.

In accordance with Inspection Manual Chapter (IMC) 0612, Appendix B, "Issue Disposition Screening," the team determined that the issue was more than minor because the issue was associated with the equipment performance attribute of both the initiating events and mitigating systems cornerstones. The significantly degraded RBCLC piping resulted in an increase in the likelihood of the loss of the RBCLC system due to piping failure, which directly affected the initiating events cornerstone. The loss of the RBCLC system would also result in the loss of cooling to the feedwater and condensate pumps, the recirculation pumps, the drywell coolers, the shutdown cooling heat exchangers, and two of three instrument air compressors following a loss of coolant accident or a loss of all AC power (SBO) event where AC power is recovered

prior to core damage, which directly affected the mitigating systems cornerstone. Section 4OA3.5 discusses the risk analysis and assessment associated with this finding.

#### Enforcement

Title 10 to CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to prevent repetition. Contrary to this requirement, when significant conditions adverse to quality occurred prior to, and on May 15, 2002, involving degraded RBCLC system piping, the licensee failed to determine the cause and the extent of the condition and failed to take appropriate corrective actions to prevent recurrence. Specifically, an RBCLC system piping leak occurred on May 15, 2002, due to significant pipe corrosion, primarily as a result of an inadequate piping design, application and operation. Additionally, numerous RBCLC system leaks occurred during several preceding years. However, the cause of this condition was not determined and corrective actions were not taken, and as a result, corrosion continued to further degrade RBCLC system piping such that additional significant leaks occurred on December 5, 2002, and again on December 12, 2002. These significant leaks in December 2002 exhibited severe pipe wall loss and degraded the structural integrity of the affected piping sections. This was an apparent violation of 10 CFR 50, Appendix B, Criterion XVI. (AV 50-220/03-003-01)

#### 5. Risk Significance and Analysis of Event

##### a. Inspection Scope

The team evaluated the licensee's safety and availability assessment of the degraded condition of the RBCLC system, including the associated assumption and evaluation criteria, analysis methodology, and design inputs. The team also performed an independent risk assessment of the finding related to the degraded RBCLC system. The team evaluated the duration of the degraded condition, and the safety implications associated with the cause of the degradation. The team also interviewed the cognizant licensee risk, engineering, and operations personnel.

b. Findings

SDP Phase 1:

In accordance with NRC IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the team conducted a significance determination process (SDP) Phase 1 screening and determined that the finding degraded both the initiating event and mitigating systems cornerstones. Therefore, a SDP Phase 2 evaluation was required.

SDP Phase 2:

The SDP Phase 2 process was not designed to estimate the risk significance of a finding that resulted in an initiating event that induces a second initiating event.

SDP Phase 3:

Internal Initiating Events:

The NRC's Standardized Plant Analysis Risk (SPAR) model, Revision 3.01, was used to evaluate the significance of this finding. The team determined that the SPAR model needed to be revised to link the loss of RBCLC event tree and the anticipated transient without scram (ATWS) event tree and to reflect the possibility of a recirculation pump seal leak following the loss of the RBCLC system. This revision resulted in an increase in the baseline core damage frequency from 7.88E-6 per year to 7.91E-6 per year.

Assumptions:

1. The performance deficiency existed for in excess of a year. Therefore, the team used an exposure time of 1 year.
2. The RBCLC system piping was significantly degraded and lacked adequate structural integrity. Therefore, the dominant failure mode of the RBCLC system involved a passive failure of the piping which resulted in an increase in the likelihood of a loss of RBCLC initiating event. The initiating event frequency was determined by taking into account the existing failure modes of the system, the lack of structural integrity of the piping, the numerous leaks from the RBCLC piping over the years, and the likelihood of a leak before break in the piping. Applying engineering judgement, the team concluded that the loss of RBCLC initiating event frequency was approximately 5.0E-2 per year.
3. Loss of coolant accidents and SBO events result in drywell temperatures that induce thermal stresses in the RBCLC piping in excess of the structural capability of the piping. Therefore, the team used a conditional failure probability of 1.0 for the RBCLC system in these events.
4. Failure of the RBCLC piping would result in the inability to remove heat from the recirculation pump seals. Without cooling, the likelihood of a recirculation pump seal leak increased substantially. Therefore, the team used a seal failure

probability of 0.5, which was based on the licensee's recirculation pump seal package test results.

5. Failure of the RBCLC piping would result in system leakage in excess of the automatic makeup capability for the system. Consequently, the RBCLC expansion tank level would be lost and the operating RBCLC pumps would fail due to inadequate net positive suction head (NPSH).

The team did not credit recovery of the RBCLC system because under certain entry conditions, Annunciator Response Procedure N1-ARP-H1, "Control Room Panel H1," directed the starting of the standby RBCLC pump; and Annunciator Response Procedure N1-ARP-H1, Special Operating Procedure N1-SOP-8, "RBCLC Failure," and Operating Procedure N1-OP-11, "Reactor Building Closed Loop Cooling System," did not provide guidance to secure the operating RBCLC pumps when inadequate NPSH existed. Also, no procedural guidance existed to isolate an RBCLC leak and recover the RBCLC system. In addition, because each of the dominant accident sequences involved the failure of operator actions prior to when RBCLC would have been recovered, the likelihood of the failure of the operators to recover RBCLC would be dependent on those prior failures. Consequently, the team considered the likelihood of the operators' failure to recover the RBCLC system too high to credit.

The team revised the SPAR model to reflect these assumptions, determined a revised core damage frequency for the exposure period ( $1.32\text{E-}5$  per year) and calculated the change in core damage frequency ( $\Delta\text{CDF}$ ) for this finding due to internal initiating events.

$$\begin{aligned}\Delta\text{CDF} &= [(1.32\text{E-}5 \text{ per year}) - (7.91\text{E-}6 \text{ per year})] \\ &= 5.29\text{E-}6 \text{ per year (White)}\end{aligned}$$

This result was dominated by the following accident sequences.

Contribution to $\Delta$ CDF	Core Damage Sequence Description
4.03E-6	<ul style="list-style-type: none"> <li>• IE - Loss of RBCLC due to the degraded piping condition</li> <li>• Instrument air (IA) fails following the loss of RBCLC</li> <li>• RCS inventory is lost via either a stuck open SRV or unisolated recirculation pump seal leaks</li> <li>• Condensate and feedwater fail due to loss of RBCLC</li> <li>• Operators successfully depressurize to low pressure</li> <li>• Core Spray successfully provides inventory control</li> <li>• Suppression Pool Cooling fails due to loss of IA</li> <li>• Shutdown Cooling fails due to loss of RBCLC</li> <li>• Containment spray fails</li> <li>• Containment venting fails due to loss of IA</li> </ul>
5.71E-7	<ul style="list-style-type: none"> <li>• IE - Small break loss of coolant accident (SLOCA)</li> <li>• RBCLC fails due to the degraded piping condition following the SLOCA</li> <li>• IA fails following the loss of RBCLC</li> <li>• Condensate and feedwater fail due to loss of RBCLC</li> <li>• Operators successfully depressurize to low pressure</li> <li>• Core Spray successfully provides inventory control</li> <li>• Suppression Pool Cooling fails due to loss of IA</li> <li>• Containment spray fails</li> <li>• Containment venting fails due to loss of IA</li> </ul>
5.26E-7	<ul style="list-style-type: none"> <li>• IE - Loss of RBCLC due to the degraded piping condition</li> <li>• IA fails following the loss of RBCLC</li> <li>• Condensate and feedwater fail due to loss of RBCLC</li> <li>• Emergency condensers fail</li> <li>• Operators successfully depressurize to low pressure</li> <li>• Core Spray successfully provides inventory control</li> <li>• Suppression Pool Cooling fails due to loss of IA</li> <li>• Shutdown Cooling fails due to loss of RBCLC</li> <li>• Containment spray fails</li> <li>• Containment venting fails due to loss of IA</li> </ul>
6.80E-8	<ul style="list-style-type: none"> <li>• IE - Loss of RBCLC due to the degraded piping condition</li> <li>• IA fails following the loss of RBCLC</li> <li>• RCS inventory is lost via two or more stuck open SRVs</li> <li>• Condensate and feedwater fail due to loss of RBCLC</li> <li>• Core Spray successfully provides inventory control</li> <li>• Suppression Pool Cooling fails due to loss of IA</li> <li>• Shutdown Cooling fails due to loss of RBCLC</li> <li>• Containment spray fails</li> <li>• Containment venting fails due to loss of IA</li> </ul>

External Initiating Events:

The Nine Mile Point Unit 1 probabilistic risk assessment (PRA) model U1PRA01B, dated February 2002, includes external initiating events (e.g., seismic and fire initiating events). Therefore, the team evaluated the results obtained using the licensee's PRA model to determine the risk contribution of the significantly degraded RBCLC piping due to external initiating events.

Seismic:

The Nine Mile Point Unit 1 PRA model has six categories of seismic events. The model uses the EPRI seismic hazards curves to estimate the frequencies of each of these events. The baseline seismic-induced CDF is approximately  $1.25\text{E-}6$  per year. The licensee's PRA documentation stated that the model results using the Lawrence Livermore National Laboratory seismic hazard curves would be higher by approximately a factor of five.

The team concurred with the licensee's conclusion that the significantly degraded RBCLC piping would fail during any seismic event of 0.05g or greater in magnitude. The licensee revised their PRA model to reflect this degraded condition and determined that the increase in seismic-induced CDF was approximately  $1.03\text{E-}7$  per year. This result was dominated by a seismic-induced loss of offsite power, failure of the RBCLC piping, failure of instrument air, and failure to remove decay heat from containment. The team reviewed the results and concluded that the results were reasonable and that seismic events did not contribute significantly to  $\Delta\text{CDF}$ .

Fire:

The team determined that there were no fire scenarios that would result in conditions that would fail the significantly degraded RBCLC piping. In addition, the team determined that the significantly degraded RBCLC piping did not adversely impact the mitigation of any fire events. Therefore, the team concluded that fire events did not contribute significantly to  $\Delta\text{CDF}$ .

High Winds, Floods, and Other External Events (HFO):

The team determined that there were no HFO events that would result in conditions that would fail the significantly degraded RBCLC piping. In addition, the team determined that the significantly degraded RBCLC piping did not adversely impact the mitigation of any HFO events. Therefore, the team concluded that HFO events did not contribute significantly to  $\Delta\text{CDF}$ .



Potential Risk Contribution due to Large Early Release Frequency.

In BWR Mark I containments, only a subset of core damage accidents can lead to large, unmitigated releases from the containment that have the potential to cause prompt fatalities prior to population evacuation. Core damage sequences of concern for BWR Mark I containments are inter-system loss of coolant accident, ATWS, SLOCA, and transient sequences. Because the dominant accident sequences for the case involving the significantly degraded RBCLC piping were transient and SLOCA sequences, the finding was screened for its potential risk contribution to large early release frequency (LERF). Using NRC Inspection Manual Chapter 0609, Appendix H, "Containment Integrity SDP," the team determined that the dominant accident sequences did not result in a contribution to LERF because these sequences resulted in core damage following containment failure due to a loss of containment heat removal. Thus, evacuation of the population would have been carried out in sufficient time so that these accident sequences would not have resulted in a contribution to LERF.

Licensee's Risk Assessment:

The licensee performed a risk evaluation of the degraded RBCLC piping and concluded that the  $\Delta$ CDF was  $9.0E-7$  per year and the  $\Delta$ LERF was  $7.5E-8$  per year. The team reviewed the licensee's results and concluded that the differences were primarily attributable to a difference in three assumptions.

First, the licensee assumed that the RBCLC piping was degraded, but it retained structural integrity for all initiating events except loss of coolant accidents, loss of drywell cooling events, and seismic events greater than 0.05g in magnitude. The licensee did not assume that the likelihood of the loss of RBCLC initiating event increased due to the condition of the RBCLC piping. The team evaluated the licensee's assumption and concluded that it was not the most appropriate assumption for the condition.

Second, the licensee assumed that the RBCLC system would fail at one preferential location and that the recirculation pump seals would be cooled by the boil off of the water that would remain in the system following the pipe rupture. As a result, the licensee assumed that the likelihood of the recirculation pump seal leak remained unchanged. The team evaluated the licensee's assumption and concluded that there was no basis to assume that the RBCLC piping would fail at one preferential location and that the remaining water in the system would adequately cool the recirculation pump seals. As a result, the team evaluated the licensee's assumption and concluded that it was not the most appropriate assumption for the condition.

Lastly, the licensee assumed that recovery of the RBCLC and IA systems was possible to provide long term heat removal from containment. The licensee assumed that the likelihood of the operators' failure to recover the RBCLC system was 0.1. The licensee based this assumption largely on the time available to perform the recovery actions and reliance on assistance from the Technical Support Center and the Emergency Operations Facility. The team evaluated the licensee's assumption and concluded that it was not the most appropriate assumption for the condition for the reasons described above (Phase 3 Assumption 5).

Analysis - Conclusion:

The safety significance of the inspection finding based on the increase in core damage frequency due to internal and external initiating events is White ( $\Delta CDF = 5.39E-6$  per year). The safety significance of the inspection finding based on the increase in large early release frequency is Green ( $\Delta LERF < 1.0E-7$  per year). Therefore, the safety significance of the inspection finding is White. A White finding represents a finding of low to moderate safety significance.

4OA5 Other

(Closed) URI 50-220/2002-06-02: RBCLC System Piping Degradation Due to Corrosion. This item was opened to evaluate the safety and risk significance of the degraded condition of the RBCLC system. This NRC special inspection team performed this evaluation, and identified associated licensee performance deficiencies as documented in this inspection report. Therefore, this item is closed, and further tracking and follow-up of this issue will be accomplished via the enforcement tracking/violation open item identified in this report (See Section 4OA3.4 of this report).

4OA6 Meetings, including Exit

The inspectors presented the inspection results to Mr. J. Conway, Vice President, Nine Mile Point, and other members of licensee management at the conclusion of the onsite inspection on February 14, 2003, and on March 7, 2003, upon completion of the combined onsite and in-office inspection activities. The licensee acknowledged the findings presented. The team reviewed some proprietary documents during the inspection, and these documents were identified and discussed by the NRC at the exit meeting. Based upon subsequent discussions with the licensee, none of the information presented at the exit meeting and included in this report was considered proprietary.

## ATTACHMENT 1

### KEY POINTS OF CONTACT

#### Licensee Personnel

M. Alvi, Lead Engineer, Design Structural  
K. Churchill, System Engineer  
K. Embry, Licensing Engineer  
T. Kulczycky, Principle Engineer, Reliability Engineering  
T. Kurtz, Engineering Services  
B. Montgomery, Manager, Engineering Services  
J. Murphy, Engineer, Mechanical Design  
B. Randall, General Supervisor, System Engineering  
J. Richards, Manager, Chemistry

#### NRC Personnel

G. Hunegs, Senior Resident Inspector, NMP  
J. Trapp, Chief, Projects Branch 1, Region I

### LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

#### Opened

50-220/2003-03-01 AV Failure to Determine the Cause of a Significant Condition Adverse to Quality and Implement Corrective Action to Prevent Repetition, Associated with Severe Corrosion of the RBCLC System.

#### Closed

50-220/2002-06-02 URI RBCLC System Degradation

### LIST OF DOCUMENTS REVIEWED

#### Drawings:

C-18011-C Instrument Air System P&I Diagram, Sheet 1, Rev. 48  
C-18018-C Reactor Shutdown Cooling System P&I Diagram, Sheet 1, Rev. 25  
C-18022-C RBCLC System P&I Diagram, Sheet 2, Rev. 43  
C-18022-C TBCLC System P&I Diagram, Sheet 3, Rev. 30  
C-18298-C RBCLC System Piping at Drywell Air Coolers and Equipment Drain Sump Pit Coolers, Rev. 6  
C-18299-C RBCLC System Piping at Drywell Air Coolers and Equipment Drain Sump Pit Coolers, Rev. 5  
C-26855-C RBCLC System No. 70 Piping Isometric, Rev. 2

Calculations:

S13.4-70-TP15 RBCLC, Rev. 0

Licensing Documents:

Nine Mile Point Unit 1 Technical Specifications  
Updated Safety Analysis Report - Nine Mile Point Unit 1 Nuclear Station

Deviation Event Reports (DER):

1991-560	2002-3143
1992-480	2002-5166
1993-339	2002-5193
2000-2139	2002-5193
2000-3268	2002-5280
2001-5201	2002-5305
2002-2383	

Procedures:

N1-OP-11 Reactor Building Closed Loop Cooling System, Rev. 20  
N1-MRM-REL-0104 Maintenance Rule Manual, Rev. 16  
N1-MRM-REL-0105 Maintenance Performance Criteria, Rev. 14

Miscellaneous Documents:

Failure Analysis of Flow Switch from the RBCLC to Recirculation Pump 32-190 Cooling Water, NMP-1, dated July 29, 2002

Design Change Package N1-02-219 Drywell Equipment Drain Tank Coolers RBCLC  
Outlet Re-design," Rev. 0

Draft Evaluations

DER 2002-5305 Category 1 Root Cause Evaluation (Organizational and Cultural Assessment - Unit 1 RBCLC System Events)

Safety and Availability Assessment - Unit 1 - RBCLC Pipe Leakage Inside Primary Containment

Reliability Group Technical Report - Unit 1 Drywell Heatup and RBCLC Drain Unit Cooler Piping Temperature Response Evaluation

Safety and Availability Assessment - Unit 1 - RBCLC Leak Study

## LIST OF ACRONYMS USED

AC	Alternating Current
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
AV	Apparent Violation
BWR	Boiling Water Reactor
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CMTR	Certified Material Test Report
DER	Deviation Event Report
ECCS	Emergency Core Cooling System
EPRI	Electric Power Research Institute
FW	Feedwater
HFO	High Winds, Floods, and Other External Events
IA	Instrument Air
IE	Initiating Events
IMC	Inspection Manual Chapter
LERF	Large Early Release Frequency
MDC	Mechanical Design Criteria
MS	Mitigating Systems
MSIV	Main Steam Isolation Valve
NEI	Nuclear Energy Institute
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
ppb	Parts Per Billion
PRA	Probabilistic Risk Assessment
RBCLC	Reactor Building Closed Loop Cooling
RCS	Reactor Coolant System
SBO	Station Blackout
SDP	Significance Determination Process
SLOCA	Small Break Loss of Coolant Accident
SPAR	Standardized Plant Analysis Risk
SRV	Safety Relief Valve
TBCLC	Turbine Building Closed Loop Cooling
URI	Unresolved Item
$\Delta$ CDF	Change in Core Damage Frequency
$\Delta$ LERF	Change in Large Early Release Frequency

**ENCLOSURE 2**

February 4, 2003

**MEMORANDUM TO:** James Trapp, Manager  
Special Inspection

Steve Pindale, Leader  
Special Inspection

**FROM:** A. Randolph Blough, Director /RA/  
Division of Reactor Projects

**SUBJECT:** SPECIAL INSPECTION CHARTER - NINE MILE POINT  
UNIT NO. 1

A special inspection has been established to inspect and assess the reactor building closed loop cooling (RBCLC) system piping degradation that was identified at Nine Mile Point Unit 1 in December 2002. The special inspection will be conducted onsite during the week of February 10, 2003, and will include:

**Manager:** James Trapp, Chief, Projects Branch 1

**Leader:** Steve Pindale, DRS

**Members:** Suresh Chaudhary, DRS  
Edward-Knutson, Resident Inspector at Nine Mile Point  
Eugene Cobey, Senior Risk Analyst - Part Time

On December 5, Unit 1 was shut down due to unidentified system leakage inside the drywell. Leakage was subsequently identified from the RBCLC system. The piping degradation resulted in system leaks and potentially adversely impacted the structural integrity of the system. The RBCLC system is cooled by service water and provides demineralized water to cool auxiliary equipment located in the reactor, turbine and waste disposal building. The RBCLC system provides cooling water to major components including equipment drain tank coolers, drywell air coolers and recirculation pump coolers located in the drywell in addition to fuel pool heat exchangers, instrument air compressors, feedwater pumps, condensate pumps and feedwater booster pumps.

This special inspection was initiated in accordance with NRC Inspection Procedure 71153 "Event Follow-up" and NRC Management Directive 8.3, "NRC Incident Investigation Program." The decision to perform this special inspection was based largely on the postulated loss of safety function of the feedwater coolant injection system (high pressure reactor makeup source is dependent on RBCLC) and the increased conditional core damage probability (CCDP) for this condition. The inspection will be performed in accordance with the guidance of NRC Inspection Procedure 93812, "Special Inspection," and the inspection report will be issued within 45 days following the exit meeting for the inspection. If you have any questions regarding the objectives of the attached charter, please contact James Trapp at 610-337-5186.

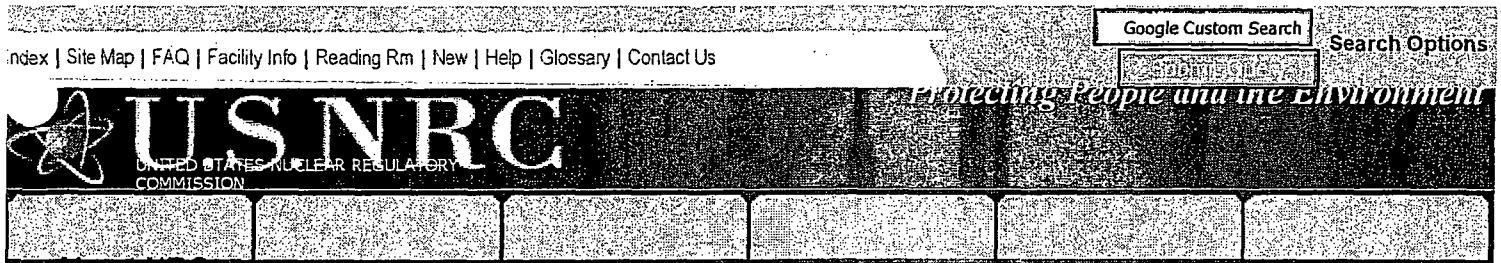
Attachment: Special Inspection Charter

**Special Inspection Charter  
Nine Mile Point Unit No. 1  
Reactor Building Closed Loop Cooling System Piping Degradation**

The objectives of the inspection are to determine the facts and assess the conditions surrounding the reactor building closed loop cooling system piping degradation that occurred at Nine Mile Point Unit 1 on December 2002. Specifically the inspection should:

- a. Assess the adequacy of the licensee's root cause evaluation of the condition.
- b. Assess the adequacy of the licensee's extent of condition review and corrective actions for the condition.
- c. Assess the effectiveness of prior corrective actions for the previous leaks in the reactor building closed loop cooling system.
- d. Evaluate the licensee's assessment of the risk significance of the condition, including evaluation of all input assumptions.
- e. Independently evaluate the risk significance of the condition.
- f. Assess the applicability/effectiveness of the licensee's piping inspection program.
- g. Assess the design adequacy of the RBCLC piping material compatibility.
- h. Document the inspection findings and conclusions in a special inspection report in accordance with Inspection Procedure 93812 within 45 days of the exit meeting for the inspection.





Home > Electronic Reading Room > Document Collections > Fact Sheets > Power Upgrades for Nuclear Plants

## Fact Sheet on Power Upgrades for Nuclear Plants

- Nuclear Reactors
- Printable Version
- Nuclear Materials
- Background
- Radioactive Waste
- Nuclear Security
- Public Meetings

Utilities have been using power upgrades since the 1970s as a way to increase the power output of their nuclear plants. As of July 2004, the NRC has completed 101 such reviews resulting in a gain of approximately 12,548 MWt (megawatts thermal) or 4,183 MWe (megawatts electric) at existing plants (see Table 1). Collectively, an equivalent of about four nuclear power plant units has been gained through implementation of power upgrades at existing plants. NRC licensees have indicated they plan to ask for power upgrades over the next five years, that if approved, would add another 2,841 MWt (947 MWe) to the nation's generating capacity.

### & Involvement Discussion

To increase the power output of a reactor, typically a more highly enriched uranium fuel is added. This enables the reactor to produce more thermal energy and therefore more steam, driving a turbine generator to produce electricity. In order to accomplish this, components such as pipes, valves, pumps, heat exchangers, electrical transformers and generators, must be able to accommodate the conditions that would exist at the higher power level. For example, a higher power level usually involves higher steam and water flow through the systems used in converting the thermal power into electric power. These systems must be capable of accommodating the higher flows.

In some instances, licensees will modify and/or replace components in order to accommodate a higher power level. Depending on the desired increase in power level and original equipment design, this can involve major and costly modifications to the plant such as the replacement of main turbines. All of these factors must be analyzed by the licensee as part of a request for a power upgrade, which is accomplished by amending the plant's operating license. The analyses must demonstrate that the proposed new configuration remains safe and that measures continue to be in place to protect the health and safety of the public. These analyses are reviewed by the NRC before a request for a power upgrade is approved.

Power upgrades can be classified in three categories: (1) measurement uncertainty recapture power upgrades, (2) stretch power upgrades, and (3) extended power upgrades.

**1) Measurement uncertainty recapture power upgrades** are power increases less than two percent and are achieved by using enhanced techniques for calculating reactor power. This involves the use of state-of-the-art devices to more precisely measure feedwater flow which is used to calculate reactor power. More precise measurements reduce the degree of uncertainty in the power level which is used by analysts to predict the ability of the reactor to be safely shut down under some accident conditions.

**2) Stretch power upgrades** are typically on the order of up to seven percent and usually involve changes to instrumentation settings. Stretch power upgrades generally do not involve major plant modifications. This is especially true for boiling-water reactor plants. In some limited cases where plant equipment was operated near capacity prior to the power upgrade, more substantial changes may be required.

**3) Extended power upgrades** are usually greater than stretch power upgrades and have been approved for increases as high as 20 percent. Extended power upgrades usually require significant modifications to major pieces of plant equipment such as the high pressure turbines, condensate pumps and motors, main generators, and/or transformers.

## Review Process

Power upgrades are submitted to NRC as license amendment requests. The applications and reviews are complex and involve many areas of NRC including various technical divisions of the Office of Nuclear Reactor Regulation and the Office of the General Counsel. Some reviews may also involve the Office of Nuclear Regulatory Research and the Advisory Committee on Reactor Safeguards. In evaluating a power upgrade request, NRC reviews data and accident analyses submitted by a licensee to confirm that the plant can operate safely at the higher power level. Reviews of power upgrade requests are a high priority and are therefore, being conducted on accelerated schedules.

Regulatory Issue Summary (RIS) 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Upgrade Applications," dated January 31, 2002, covers analyses of the effect of the power upgrade on things such as critical equipment, major plant systems, and emergency operating procedures. The RIS outlines the staff's information needs for reviewing measurement uncertainty recapture power upgrade applications and is intended to result in a more efficient and effective review process. Standardization of licensee's submittals, improvements in the quality of submittals, and more focused reviews by the staff could improve the timeliness of power upgrade reviews.

Based on results of its industry survey, NRC expects to receive only one stretch power upgrade over the next five years. Therefore, NRC's efforts for improving the power upgrade application and review processes initially focused on measurement uncertainty and extended power upgrades. Efficiencies gained there will be applied to improve the stretch power upgrade review process.

Reviews of extended power upgrade applications were initially estimated to take up to 18 months, but have been completed more quickly. The Duane Arnold, Dresden 2 and 3, and Quad Cities 1 and 2 extended power upgrades were completed in just under 12 months. This included coordination and review with the NRC's Advisory Committee on Reactor Safeguards -- an independent panel of technical experts from diverse fields that advises the Commission.

NRC issued a review standard for extended power upgrades, RS-001, in December 2003. The standard is a first-of-a-kind document that provides a comprehensive process and technical guidance for reviews by the NRC staff, and also provides useful information to licensees considering applying for an extended upgrade. The NRC's Advisory Committee on Reactor Safeguards endorsed RS-001 as an "excellent review standard." The staff is currently using this standard to review the proposed 20-percent upgrade for Vermont Yankee and the proposed 8-percent upgrade for the Waterford Steam Electric Station. The staff will closely monitor these upgrade reviews to identify any issues related to using RS-001.

To keep the public informed of its activities, NRC publishes a notice in the *Federal Register* (1) when it receives a request from a licensee for a power upgrade, giving the public the opportunity to request a hearing; (2) after a finding of no significant environmental impact is made, if applicable; (3) if a power upgrade is approved. A press release is also issued if a power upgrade is approved.

## Current Status

### Specific Applications Under Review

NRC usually has several applications for power upgrades under review at any given time. An updated list of applications under review can be found on the NRC's Web site at this address:  
<http://www.nrc.gov/reactors/operating/licensing/power-upgrades/pending-applications.html>.

### Steam Dryer Issues Following Upgrades

In 2002, steam dryer cracking and flow-induced vibration damage on components and supports for the main steam and feedwater lines have been observed at the Dresden and Quad Cities nuclear power plants, both of which use boiling water reactors, following implementation of extended power upgrades. NRC staff have determined these issues do not pose an immediate safety concern, given the plants' current operating conditions. However, steam dryers and other internal main steam and feedwater components must maintain structural integrity to prevent generating loose parts that could impact safety system or reactor plant operation. The NRC has corresponded with and met with nuclear industry groups concerning these issues since the first occurrences, and continues to examine its regulatory options based on industry actions and information available.

### Key Actions

Licensees have told NRC they plan to submit 18 power upgrade applications in the next five years as follows:

- 10 extended power upgrades
- 1 stretch power upgrade
- 7 measurement uncertainty recapture power upgrades

Based on the information provided, planned power upgrades are expected to result in an increase of about 2,841 Mwt. An updated list of anticipated future applications can be found on the NRC's Web site at this address:

<http://www.nrc.gov/reactors/operating/licensing/power-upgrades/expected-applications.html>.

## Tables

- Table 1 - Approved Power Upgrades as of June 2004
- Table 2 - Power Upgrades Currently Under Review as of June 2004
- Table 3 - Expected Future Submittals for Power Upgrades as of June 2004

**Table 1 - Approved Power Upgrades as of June 2004**

(TYPE - S = Stretch; E = Extended; MU = Measurement Uncertainty Recapture)

NO.	Plant	% Uprate	Mwt	Year Approved	TYPE
1	Calvert Cliffs 1	5.5	140	1977	S
2	Calvert Cliffs 2	5.5	140	1977	S
3	Millstone 2	5	140	1979	S
4	H. B. Robinson	4.5	100	1979	S
5	Fort Calhoun	5.6	80	1980	S
6	St. Lucie 1	5.5	140	1981	S
7	St. Lucie 2	5.5	140	1985	S
8	Duane Arnold	4.1	65	1985	S
9	Salem 1	2	73	1986	S
10	North Anna 1	4.2	118	1986	S
11	North Anna 2	4.2	118	1986	S
12	Callaway	4.5	154	1988	S
13	TMI-1	1.3	33	1988	S
14	Fermi 2	4	137	1992	S
15	Vogtle 1	4.5	154	1993	S
16	Vogtle 2	4.5	154	1993	S
17	Wolf Creek	4.5	154	1993	S
18	Susquehanna 2	4.5	148	1994	S
19	Peach Bottom 2	5	165	1994	S
20	Limerick 2	5	165	1995	S
21	Susquehanna 1	4.5	148	1995	S
22	Nine Mile Point 2	4.3	144	1995	S
23	WNP-2	4.9	163	1995	S
24	Peach Bottom 3	5	165	1995	S
25	Surry 1	4.3	105	1995	S
26	Surry 2	4.3	105	1995	S
27	Hatch 1	5	122	1995	S
28	Hatch 2	5	122	1995	S
29	Limerick 1	5	165	1996	S
30	V. C. Summer	4.5	125	1996	S

Fact Sheet on Power Upgrades for Nuclear Plants

31	Palo Verde 1	2	76	1996	S
32	Palo Verde 2	2	76	1996	S
33	Palo Verde 3	2	76	1996	S
34	Turkey Point 3	4.5	100	1996	S
35	Turkey Point 4	4.5	100	1996	S
36	Brunswick 1	5	122	1996	S
37	Brunswick 2	5	122	1996	S
38	Fitzpatrick	4	100	1996	S
39	Farley 1	5	138	1998	S
40	Farley 2	5	138	1998	S
41	Browns Ferry 2	5	164	1998	S
42	Browns Ferry 3	5	164	1998	S
43	Monticello	6.3	105	1998	E
44	Hatch 1	8	205	1998	E
45	Hatch 2	8	205	1998	E
46	Comanche Peak 2	1	34	1999	MU
47	LaSalle 1	5	166	2000	S
48	LaSalle 2	5	166	2000	S
49	Perry	5	178	2000	S
50	River Bend	5	145	2000	S
51	Diablo Canyon 1	2	73	2000	S
52	Watts Bar	1.4	48	2001	MU
53	Byron 1	5	170	2001	S
54	Byron 2	5	170	2001	S
55	Braidwood 1	5	170	2001	S
56	Braidwood 2	5	170	2001	S
57	Salem 1	1.4	48	2001	MU
58	Salem 2	1.4	48	2001	MU
59	San Onofre 2	1.4	48	2001	MU
60	San Onofre 3	1.4	48	2001	MU
61	Susquehanna 1	1.4	48	2001	MU
62	Susquehanna 2	1.4	48	2001	MU
63	Hope Creek	1.4	46	2001	MU
64	Beaver Valley 1	1.4	37	2001	MU
65	Beaver Valley 2	1.4	37	2001	MU
66	Shearon Harris	4.5	138	2001	S
67	Comanche Peak 1	1.4	47	2001	MU
68	Comanche Peak 2	0.4	13	2001	MU
69	Duane Arnold	15.3	248	2001	E
70	Dresden 2	17	430	2001	E
71	Dresden 3	17	430	2001	E
72	Quad Cities 1	17.8	446	2001	E
73	Quad Cities 2	17.8	446	2001	E
74	Waterford 3	1.5	51	2002	MU

75	Clinton	20	579	2002	E
76	South Texas 1	1.4	53	2002	MU
77	South Texas 2	1.4	53	2002	MU
78	ANO-2	7.5	211	2002	E
79	Sequoyah 1	1.3	44	2002	MU
80	Sequoyah 2	1.3	44	2002	MU
81	Brunswick 1	15	365	2002	E
82	Brunswick 2	15	365	2002	E
83	Grand Gulf	1.7	65	2002	MU
84	H. B. Robinson	1.7	39	2002	MU
85	Peach Bottom 2	1.62	56	2002	MU
86	Peach Bottom 3	1.62	56	2002	MU
87	Indian Point 3	1.4	42.4	2002	MU
88	Point Beach 1	1.4	21.5	2002	MU
89	Point Beach 2	1.4	21.5	2002	MU
90	Crystal River 3	0.9	24	2002	S
91	D.C. Cook 1	1.66	54	2002	MU
92	River Bend	1.7	52	2003	MU
93	D.C. Cook 2	1.66	57	2003	MU
94	Pilgrim	1.5	30	2003	MU
95	Indian Point 2	1.4	43	2003	MU
96	Kewaunee	1.4	23	2003	MU
97	Hatch 1	1.5	41	2003	MU
98	Hatch 2	1.5	41	2003	MU
99	Palo Verde 2	2.9	114	2003	S
100	Fort Calhoun*	1.6	24	2004	MU
101	Kewaunee	6.0	99	2004	S
102	Palisades	1.4	35	2004	MU

\* Fort Calhoun later reduced power to the pre-MU level after being informed of potential instrument inaccuracies in ultrasonic flow meters used in the uprate.

**Table 2 - Power Upgrades Currently Under Review as of June 2004**

(TYPE -- S = Stretch; E = Extended; MU = Measurement Uncertainty Recapture)

No.	Plant	% Uprate	MWt	Submittal Date	Projected Completion Date	Type
1	Vermont Yankee	20	319	09/10/03	January 2005	EPU
2	Waterford	8	275	11/13/03	January 2005	EPU
3	Indian Point 2	3.3	102	01/29/04	October 2004	S
4	Seabrook	5.2	176	03/17/04	TBD	S
5	Indian Point 3	4.85	148	06/25/04	TBD	S
6	Browns Ferry 2	15	494	06/25/04	TBD	EPU
7	Browns Ferry 3	15	494	06/25/04	TBD	EPU

8	Browns Ferry 1	20	659	06/28/04	TBD	EPU
9	Palo Verde 1	2.94	114	07/09/04	TBD	S
10	Palo Verde 3	2.94	114	07/09/04	TBD	S

**Table 3 - Expected Future Submittals for Power Upgrades as of June 2004**

<u>Calendar Year</u>	<u>Total Upgrades Expected</u>	<u>Measurement Uncertainty Recapture Upgrades</u>	<u>Stretch Power Upgrades</u>	<u>Extended Power Upgrades</u>	<u>Megawatts Thermal</u>	<u>Approximate Megawatts Electric</u>
<u>4</u>	<u>1</u>	<u>1</u>	<u>0</u>	<u>0</u>	<u>24</u>	<u>8</u>
<u>5</u>	<u>7</u>	<u>3</u>	<u>0</u>	<u>4</u>	<u>1,291</u>	<u>430</u>
<u>6</u>	<u>3</u>	<u>3</u>	<u>0</u>	<u>0</u>	<u>161</u>	<u>54</u>
<u>7</u>	<u>6</u>	<u>0</u>	<u>1</u>	<u>5</u>	<u>843</u>	<u>281</u>
<u>8</u>	<u>1</u>	<u>0</u>	<u>0</u>	<u>1</u>	<u>522</u>	<u>174</u>
<u>TOTAL</u>	<u>18</u>	<u>7</u>	<u>1</u>	<u>10</u>	<u>2,841</u>	<u>947</u>

2004

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## Power Uprate History

Date	Reactor	Unit	Event
19770926	Calvert Cliffs	Unit 1	The NRC approved a 5.5 percent increase in the maximum licensed power level.
19770926	Calvert Cliffs	Unit 2	The NRC approved a 5.5 percent increase in the maximum licensed power level.
19790625	Millstone	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19790629	H. B. Robinson	Unit 2	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19800815	Fort Calhoun	Unit 1	The NRC approved a 5.6 percent increase in the maximum licensed power level.
19811123	St. Lucie	Unit 1	The NRC approved a 5.5 percent increase in the maximum licensed power level.
19850301	St. Lucie	Unit 2	The NRC approved a 5.5 percent increase in the maximum licensed power level.
19850327	Duane Arnold		The NRC approved a 4.1 percent increase in the maximum licensed power level.
19860206	Salem	Unit 1	The NRC approved a 2 percent increase in the maximum licensed power level.
19860825	North Anna	Unit 1	The NRC approved a 4.2 percent increase in the maximum licensed power level.
19860825	North Anna	Unit 2	The NRC approved a 4.2 percent increase in the maximum licensed power level.
19880330	Callaway	Unit 1	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19880726	Three Mile Island	Unit 1	The NRC approved a 1.3 percent increase in the maximum licensed power level.
19920909	Fermi	Unit 2	The NRC approved a 4 percent increase in the maximum licensed power level.
19930322	Alvin W. Vogtle	Unit 1	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19930322	Alvin W. Vogtle	Unit 2	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19931110	Wolf Creek	Unit 1	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19940411	Susquehanna	Unit 2	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19941018	Peach Bottom	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19950216	Limerick	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19950222	Susquehanna	Unit 1	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19950428	Nine Mile Point	Unit 2	The NRC approved a 4.3 percent increase in the maximum licensed power level.
19950502	Columbia Generating Sta		The NRC approved a 4.9 percent increase in the maximum licensed power level.
19950718	Peach Bottom	Unit 3	The NRC approved a 5 percent increase in the maximum licensed power level.
19950803	Surry	Unit 1	The NRC approved a 4.3 percent increase in the maximum licensed power level.
19950803	Surry	Unit 2	The NRC approved a 4.3 percent increase in the maximum licensed power level.
19950831	Edwin L Hatch	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
19950831	Edwin L Hatch	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19960124	Limerick	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
19960412	Virgil C. Summer		The NRC approved a 4.5 percent increase in the maximum licensed power level.
19960523	Palo Verde	Unit 1	The NRC approved a 2 percent increase in the maximum licensed power level.
19960523	Palo Verde	Unit 2	The NRC approved a 2 percent increase in the maximum licensed power level.
19960523	Palo Verde	Unit 3	The NRC approved a 2 percent increase in the maximum licensed power level.
19960926	Turkey Point	Unit 3	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19960926	Turkey Point	Unit 4	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19961101	Brunswick	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
19961101	Brunswick	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.

# Power Uprate History

Date	Reactor	Event
19961206	James A. FitzPatrick	The NRC approved a 4 percent increase in the maximum licensed power level.
19980429	Joseph M. Farley Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
19980429	Joseph M. Farley Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19980908	Browns Ferry Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19980908	Browns Ferry Unit 3	The NRC approved a 5 percent increase in the maximum licensed power level.
19980916	Monticello	The NRC approved a 6.3 percent increase in the maximum licensed power level.
19981022	Edwin I Hatch Unit 1	The NRC approved a 8 percent increase in the maximum licensed power level.
19981022	Edwin I Hatch Unit 2	The NRC approved a 8 percent increase in the maximum licensed power level.
19990930	Comanche Peak Unit 1	The NRC approved a 1 percent increase in the maximum licensed power level.
20000509	LaSalle County Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
20000509	LaSalle County Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
20000601	Perry Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
20001006	River Bend Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
20001026	Diablo Canyon Unit 1	The NRC approved a 2 percent increase in the maximum licensed power level.
20010119	Watts Bar Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010504	Braidwood Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
20010504	Braidwood Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
20010504	Byron Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
20010504	Byron Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
20010525	Salem Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010525	Salem Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010706	San Onofre Unit 2	The NRC issued license amendment 180 increasing the maximum reactor power level to 3,438 megawatts from 3,390 megawatts.
20010706	San Onofre Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010706	San Onofre Unit 3	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010706	San Onofre Unit 3	The NRC issued license amendment 171 increasing the maximum reactor power level to 3,438 megawatts from 3,390 megawatts.
20010706	Susquehanna Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010706	Susquehanna Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010719	San Onofre Unit 3	The NRC issued license amendment raising maximum reactor power level to 3,438 megawatts.
20010730	Hope Creek Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010924	Beaver Valley Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010924	Beaver Valley Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20011012	Comanche Peak Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20011012	Comanche Peak Unit 2	The NRC approved a 0.4 percent increase in the maximum licensed power level.
20011012	Shearon Harris Unit 1	The NRC approved a 4.5 percent increase in the maximum licensed power level.
20011106	Duane Arnold	The NRC approved a 15.3 percent increase in the maximum licensed power level.



## Power Uprate History

Date	Reactor	Event
20011107	Duane Arnold	The NRC issued license amendment 243 increasing the maximum reactor power level to 1,912 megawatts.
20011221	Dresden Unit 2	The NRC approved a 17 percent increase in the maximum licensed power level.
20011221	Dresden Unit 3	The NRC approved a 17 percent increase in the maximum licensed power level.
20011221	Quad Cities Unit 1	The NRC approved a 17.8 percent increase in the maximum licensed power level.
20011221	Quad Cities Unit 2	The NRC approved a 17.8 percent increase in the maximum licensed power level.
20020329	Waterford Unit 3	The NRC approved a 1.5 percent increase in the maximum licensed power level.
20020405	Clinton Unit 1	The NRC approved a 20 percent increase in the maximum licensed power level.
20020412	South Texas Project Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20020412	South Texas Project Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20020424	Arkansas Nuclear One Unit 2	The NRC approved a 7.5 percent increase in the maximum licensed power level.
20020430	Sequoyah Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20020430	Sequoyah Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20020531	Brunswick Unit 1	The NRC approved a 15 percent increase in the maximum licensed power level.
20020531	Brunswick Unit 2	The NRC approved a 15 percent increase in the maximum licensed power level.
20021010	Grand Gulf Unit 1	The NRC approved a 1.7 percent increase in the maximum licensed power level.
20021105	H. B. Robinson Unit 2	The NRC approved a 1.7 percent increase in the maximum licensed power level.
20021122	Peach Bottom Unit 2	The NRC approved a 1.62 percent increase in the maximum licensed power level.
20021122	Peach Bottom Unit 3	The NRC approved a 1.62 percent increase in the maximum licensed power level.
20021126	Indian Point Unit 3	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20021129	Point Beach Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20021129	Point Beach Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20021204	Crystal River Unit 3	The NRC approved a 0.9 percent increase in the maximum licensed power level.
20021220	Donald C. Cook Unit 1	The NRC approved a 1.66 percent increase in the maximum licensed power level.
20030131	River Bend Unit 1	The NRC approved a 1.7 percent increase in the maximum licensed power level.
20030204	Crystal River Unit 3	The NRC approved license amendment 205 increasing the maximum reactor power level to 2,568 megawatts.
20030502	Donald C. Cook Unit 2	The NRC approved a 1.66 percent increase in the maximum licensed power level.
20030509	Pilgrim Unit 1	The NRC approved a 1.5 percent increase in the maximum licensed power level.
20030522	Indian Point Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20030523	Indian Point Unit 2	The NRC issued license amendment 237 increasing the maximum reactor power level to 3,114.4 megawatts.
20030708	Kewaunee	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20030923	Edwin I Hatch Unit 1	The NRC approved a 1.5 percent increase in the maximum licensed power level.
20030923	Edwin I Hatch Unit 2	The NRC approved a 1.5 percent increase in the maximum licensed power level.
20030929	Palo Verde Unit 2	The NRC approved a 2.9 percent increase in the maximum licensed power level.
20040227	Kewaunee	The NRC approved a 6 percent increase in the maximum licensed power level.
20040623	Palisades	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20041028	Indian Point Unit 2	The NRC approved a 3.26 percent increase in the maximum licensed power level.

## Power Upate History

Date	Reactor	Unit	Event
20050228	Seabrook	Unit 1	The NRC approved a 5.2 percent increase in the maximum licensed power level.
20050324	Indian Point	Unit 3	The NRC approved a 4.85 percent increase in the maximum licensed power level.
20050415	Waterford	Unit 3	The NRC approved a 8 percent increase in the maximum licensed power level.
20051116	Palo Verde	Unit 1	The NRC approved a 2.9 percent increase in the maximum licensed power level.
20051116	Palo Verde	Unit 3	The NRC approved a 2.9 percent increase in the maximum licensed power level.
20060302	Vermont Yankee		The NRC approved a 20 percent increase in the maximum licensed power level.
20060522	Seabrook	Unit 1	The NRC approved a 1.7 percent increase in the maximum licensed power level.
20060711	R. E. Ginna		The NRC approved a 16.8 percent increase in the maximum licensed power level.
20060719	Beaver Valley	Unit 1	The NRC approved a 8 percent increase in the maximum licensed power level.
20060719	Beaver Valley	Unit 2	The NRC approved a 8 percent increase in the maximum licensed power level.
20070306	Browns Ferry	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.

UNITED STATES  
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
ENTERGY NUCLEAR VERMONT YANKEE, LLC	)	Docket No. 50-271-LR
and ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLB No. 06-849-03-LR
	)	
Vermont Yankee Nuclear Power Station	)	

DECLARATION OF ULRICH WITTE

1. My name is Ulrich Witte. The New England Coalition (NEC) has retained me as a consultant with respect to the above-captioned proceeding. I am a mechanical engineer with over twenty-six years professional of experience in engineering, licensing, and regulatory compliance of commercial nuclear facilities. I have considerable experience and expertise in the areas of configuration management, engineering design change controls, and licensing basis reconstitution. I have authored or contributed to two EPRI documents in the areas of finite element analysis, and engineering design control optimization programs. I have led industry guidelines endorsed by the American National Standards Institute regarding configuration management programs for domestic nuclear power plants. My 26 years of experience has generally focused on assisting nuclear plant owners in reestablishing fidelity of the licensing and design bases with the current plant design configuration, and with actual plant operations. In short, my expertise is in assisting problematic plants where the regulator found reason to require the owner to reestablish competence in safely operating the facility in accordance with regulatory requirements. My curriculum vitae is attached hereto as Attachment A.

2. I submit the following comments in support of New England Coalition's answer to Entergy's Motion For Summary Disposition of NEC Contention 4.

**I. NEC's Contention 4:**

3. The NEC raises a significant concern regarding the Flow-Accelerated Corrosion Program and asserts that the application for License Renewal submitted by Entergy for Vermont Yankee does not include an adequate plan to monitor and manage aging of plant equipment due to flow-accelerated corrosion during extended plant operation.

4. The Applicant's response summarized is that its present FAC program is consistent with industry guidance including EPRI NSAC 202L R.3 and the use of the CHECWORKS model is a central element in the FAC program implementation. In the motion for summary disposition, the Applicant states that it is relying on its current program for FAC management for the renewal period, and "furthermore, the FAC program that will be implemented by Entergy is the *same program* being carried out today, which has not been otherwise challenged by NEC, will meet all regulatory guidance."

5. The Applicant asserts that it is in full compliance with its current licensing basis regarding its FAC program, by declaration and a recent independent assessment by an industry expert who asserts that the plans for monitoring flow accelerated corrosion, including the FAC program goal of preclusion of negative design margin or actual pipe rupture, are technically adequate and comply with the licensing basis requirements.

**II. Summary of Declarant's Analysis:**

6. After a detailed review of the record provided to NEC regarding the Flow-Accelerated Corrosion Program, my conclusion is that the FAC program as found to date

appears to have been in non-compliance with its current licensing basis (CLB) from about 1999 through 2006. This is evidenced by the licensee's own assessments, audits, and Condition Reports, roll up of numerous cornerstone reports, and focused self assessments. Corrective actions from approximately five Condition Reports (CRs) remained open for as much as four years. The last CR 2006-2699 regarding FAC was written on August 30, 2006, but apparently never was provided to NEC, and collects approximately 6 corrective actions to the program that had been ignored and whose current status is unknown to NEC. The CR remains open today. In addition, the most recent FAC inspection was performed under superseded procedures and the results therefore are potentially of no programmatic value.

7. The licensee seems to have neglected its own CLB, and did not conform to EPRI guidance in its use of the CHECWORKS model for as much as eight years, except possibly with respect to the feedwater system. The feedwater system FAC review was run using 1999 UT data. Yet the results were not used in the RFO 24 outage. To be at least marginally a predictive modeling tool, the CHECWORKS model should have been kept current for successive outages, including multiple systems changes (as defined by NSAC) that were required to be managed for FAC as far back as 1999. The predictive capability of CHECWORKS was virtually non-existent for this period, even if the program (which depends heavily on trending of data of multiple outages) was incorporated in one plunge in 3<sup>rd</sup> quarter 2006.

8. Had data from previous FAC inspections been routinely entered into CHECWORKS, the selection of grid points and ranking would have provided a better historical perspective on where to inspect in successive outages and finally the current outage. With the exception of VY's strength in reactively replacing piping or components

during repairs or maintenance with FAC resistant material, the program itself was not effective as a predictive modeling tool. Simply stated, once something ruptured or was found to be outside its design margin, it was replaced in a reactive management approach. Proactive management of the program to *preclude failures* has been inadequate for the FAC program.

9. Even the most recent inspection completed for RFO26 appears to have been structured around procedures that were superseded, and scoping requirements to establish a new baseline of pipe geometry and as found wall thickness, was based on stale data, and the upper tiered governing procedure that was used had not been revised since 2001, and was therefore void.

10. The current program level procedure had been in existence since March 2006. Scoping was done in May of 2006 under the void procedure, and updating of CHECWORKS was not done until 3rd quarter 2006. Grid points, scope selection, and small bore piping susceptibility does not appear to have been ranked under NSAC 202L guidance or in an orderly trending of data by CHECWORKS based upon repeated passes with new grid points selected and new rankings selected. Data input and passes by CHECWORKS was not accomplished on an outage by outage basis.

11. With only 63 points examined in RFO26, the baseline for the power up-rate conditions appear not to have been established. I found it troubling that RFO 26 results were provided to the ACRS on June 5, 2007, but as yet apparently were not disclosed to NEC. I also found it troubling that the "Summary of Observations During VY Site Visit," by an expert and author of CHECWORKS, submitted on May 29, 2007 (after RFO 26), did not examine RFO26 results, nor apparently any data newer than late 2005 regarding

the FAC program. As a result of the apparently incomplete review by the CHECWORKS author and independent reviewer, I cannot support his conclusion.

12. Finally, after my review of the list of 22 undisputed facts, provided in Entergy's motion for summary disposition, it appears that 17 are material, and have a clear basis to be challenged by NEC. Many are not factual at all, but appear to be opinion, and argument supporting the Applicant's assertion of compliance with its current licensing basis.

13. Given the uniqueness of VY as the first Constant Pressure Power Uprate to 120% power, in particular when only one other plant out of the fleet of 102 went to 120% power in one step, CHECWORKS has little industry benchmarking data, and is of marginal use.

14. Of note is that the single other plant, Clinton Power Station, was inspected by the NRC, including review of the FAC program, after up-rate in January 2003, and the program was found to comply with its licensing basis including NSAC 202L and use of CHECWORKS. Program inputs were fully incorporated from previous inspection data and heat balance up-rate data. Wear rates were predicted to increase 8% because of up rated power conditions. Although this increase was a concern to the regulator, the program was found adequate. Yet only nine months later, Clinton experienced a FAC rupture. It is relevant that this failure occurred approximately 16 years after Clinton received its operating license in 1987—while apparently complying with its CLB and the EPRI guidance. See attachments Q and G.

15. Surry, where a rupture due to FAC killed four people, failed after 15 years of operation, and required 190 component replacements due to FAC. Pleasant Prairie, a fossil plant with similar conditions, endured a catastrophic FAC failure at 13 years, and a Japanese plant failed without warning, killing five people, simply because of an

administrative oversight to inspect only one missed component section. These programs were not specifically using aging management tools. The latter event occurred with nothing more than an administrative failure to routinely inspect a known FAC susceptible component.

16. I fully concur with NEC's consultant Dr. Joram Hopenfeld that benchmarking will be required through the number of years when unmanaged FAC failures begin to typically emerge, such as operational age of the Surry plant when the FAC failure occurred in December of 1986.

**III. Licensing basis for management of flow-accelerated corrosion at VY and review of the program implementation**

17. I reviewed the FAC program by four parts: Part A, examining the current licensing basis; Part B, the *implementation* of the licensing basis; Part C, the Licensee's *own record* of problems with implementation; Part D, *my independent observations* based on the record provided to NEC, and the requirements for implementing an effective program under NRC endorsed guidance, which the Licensee has stated that it has complied with.

**a. The current licensing Basis and the proposed licensing basis for the flow accelerated corrosion program:**

18. My review includes the following documents to establish the current licensing basis, and the current status of application for license renewal.

1. NUREG 1801 Rev 1, §XI-M17, Flow Accelerated Corrosion
2. EPRI NSAC 202L Rev. 3
3. CHECWORKS EPRI procedures provided by the Applicant



4. Commitments made by the licensee including the following<sup>1</sup>:
- i. USNR generic letter 89-08, Erosion corrosion –induced pipe wall thinning;
  - ii. Vermont Yankee Letter to USNRC;
  - iii. Vermont Yankee letter to the USNRC, Vermont Yankee Response to NRC Bulletin No. 87-01: Thinning of Pipe Walls in Nuclear Power Plants, dated September 11, 1987;
  - iv. Vermont Yankee letter to the USNRC, Supplement to Vermont Yankee Response to NRC Bulletin No. 87-01: Thinning of Pipe Walls in Nuclear Power Plants, dated December 24, 1987;
  - v. USNRC Generic Letter 90-05, Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2 and 3 Piping, dated June 15, 1990;
  - vi. Vermont Yankee letter to the USNRC, request from code relief for use of ASME Code Case N-597, as an alternative to analytical evaluation of wall thinning;
  - vii. USNRC letter to Vermont Yankee, Vermont Yankee Nuclear Power Station—Relief request for use of ASME code case N-597 as an Alternative Analytical Evaluation of wall thinning (TAC No. MB1530) dated July 27, 2001. NVY 01-74;
  - viii. VY memo: J.F Calchera to OEC (R. McCullough), subject: response to commitment item: ER-990876\_01, Reevaluate Feedwater Heater Inspection Program to address Ownership, dated April 25, 2000.

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<sup>1</sup> Items i., ii, iii, iv, and viii listed as commitments were not provided to NEC but were only referenced in Entergy's program level documents, and therefore were not directly reviewed. They do not appear on Entergy's Appendix A, licensee renewal list, but are listed in program level documents that were valid until March 15, 2006.

19. Industry Guidance and other records that are used for interpreting VY position regarding license renewal include:

- ix. Flow accelerated corrosion in power plants TR-106611-R1, published by EPRI in 1999.
- x. Official Transcript Advisory Committee on Reactor Safeguards subcommittee on Power Upgrades November 30, 2005
- xi. RAI SPLB-A-1 (LR001576)
- xii. Section 12-2 Wear rate analysis (Excerpt from an EPRI report)
- xiii. VYNPS License renewal Project Aging Management Program Evaluation Results. (NEC00113191)

b. **Implementation of the Flow Accelerated Program in accordance with the CLB.**

20. I reviewed the following documents to ensure the implementation of the FAC program in accordance with the CLB:

- a. ENN-DC-315, Rev. 1, "Flow Accelerated Program".
- b. VY-PP7028, Piping Flow Accelerated Corrosion Inspection Program.
- c. VY -PP7028, FAC Inspection program PP 7028- 2007 Refueling outage.
- d. VY -PP7028, piping inspection program, FAC inspection records for 2005 refueling outage.
- e. ENN-CS-S-008, rev 0, effective 9/28/2005, pipe wall thinning structural evaluation.
- f. DP-0072.

**c. Review of Inspection Histories, EPRI Reviews, Quality Assurance Reports, Cornerstone roll-ups, focused self assessments, Condition Reports, and Independent Assessments, and NRC Inspection Reports.**

21. In addition, I reviewed inspection histories, Condition Reports, quality assurance reports, and one cornerstone report rollup on trending in the FAC Program 2003 through 2006, NRC inspections, and various revisions to VPLRP subsections and revisions. The list included the following:

- a. Focused Self Assessment Report, Vermont Yankee Piping Flow Accelerated Corrosion Inspection Report, Condition Report LO-VTYLO-2003-0327.
- b. Audit No. QA-8-2004-VY1, Engineering Programs, dated 11/22/2004.
- c. EPRI review of Vermont Yankee Nuclear Power Flow-accelerated corrosion, dated February 28, 2000.
- d. CR -VTY-2005-02239.
- e. Cornerstone Rollup update last dated 10/23/2006.
- f. Summary of Observations During VY Site Visit, submitted May 29, 2007.
- g. VYPNS License Renewal Project Aging Management Program Evaluation Results.<sup>2</sup>

IV. Current status of the FAC Program with respect to the licensing basis.

22. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

<sup>2</sup> These documents were typically provided to NEC in fragments, with no title page, no document date, no record of whether the documents were current and had superseded others, and no signature or references to the author. They are referenced by Bates number only.



[REDACTED] The record indicates the VYNPS FAC program only partially implemented its licensing basis requirements to achieve a successful FAC program and that the licensee was aware of the problematic state of the program for many years. See e.g., , Attachment G at 6-25; Attachment J, Cornerstone rollup report (October 23, 2006) at page NEC038422.

25. The self identified deficiencies in Entergy's current Vermont Yankee Nuclear Power Station (VYNPS) Flow Accelerated Corrosion (FAC) Program are identified in multiple documents, and are detailed in paragraphs 26-43 of this Declaration.

26. Perhaps most significantly, it appears that Entergy was first notified by EPRI as early as 2000, (See, Attachment H) [REDACTED]

[REDACTED]  
[REDACTED] Entergy apparently ignored the warning. More troubling is that it continued to be in non-compliance with its licensing basis through the years 1999-2006. This deficiency was again noted in late 2004 under an internal quality assurance audit, and two Condition Reports were written. See, Attachment B, Quality Assurance Audit of Engineering Programs, QA-8-2004-VY-1 and Attachment I, Condition Reports.

27. Relevant data apparently was not fully entered into the CHECWORKS model until the third quarter of 2006. See, Attachment J, Cornerstone rollup report (October 23, 2006) at page NEC08424 ("CHECWORKS models and wear date analysis updated with all previous inspection in 3<sup>rd</sup> quarter 2006."). The October 23, 2006 rollup thus confirms that the model was not kept current during a seven year period, and susceptible locations may

not have been inspected during this time period. This lengthy lapse may have significantly weakened the trending capability of the software, both during the lapse period and presently.

28. The plant was essentially operating in a state in which component wear was improperly trended, and pipe conditions were actually unknown. Reliance on CHECWORKS for this time period for predicting grid points, ranking susceptible components, and inspecting new points was therefore virtually without technical or empirical value. The predictability goal of CHECWORKS is lost, and essentially it became a data collection repository, with the possible exception of the feedwater system.

29. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

30. In 2004, at least four VYNPS components, including the condensate system and the extraction steam systems, were determined to have "negative time to T<sub>min</sub>," meaning that wall thinning was being predicted as beyond operability limits and should be considered unsafe with potential rupture at anytime. See, Attachment G, Cornerstone rollup at page NEC 017893. "Negative cycles of operations," meaning wall thinning *beyond* acceptable code limits, were also predicted. The hours were substantial—predicting potential code violation or failure should have occurred 3000+ hours previously

to October 23, 2006. It is surprising that the Licensee apparently did not write Condition Reports for this condition. I do not believe that NEC received any notice nor any Condition Reports relevant to this significant indication by CHECWORKS predicting imminent potential pipe rupture. Yet the plant was operating with the CHECWORKS code predicting wall thinning, and I have not seen any inspection or audit discussing this situation, however, it does appear on the RF0 24 Inspection Plan, page 5 of Attachment R. Oddly with the same number of negative hours to time to Tmin. In addition, the plan provided wear data observed of 30% increase at Quad Cities and Dresden after the uprate. *Id.* at 41.

31. The VYNPS FAC program was deemed unsatisfactory under quality assurance review dated 11/22/2004, and two Condition Reports were written. *See*, Attachment B at 2. The report notes on page 5 the need for program management to ensure "update of susceptible piping to be identified and modifications to be incorporated." *Id.* at 5. In addition, the report noted that cross discipline review required by procedure had not been performed. *Id.*

32. The 2006 cornerstone report shows a number of indicators yellow- with lists of open CR corrective actions, and a new CR written in August 30, 2006. *See eg*, Attachment J at pages NEC038419, NEC 038422. The report lists six corrective actions and four CRs that were written as early as 2003 that remain open. *Id.* at NEC038424. These include references to a number of progress indicators, but continue to express concern over the program, and the slow progress to update the CHECWORKS model. I reviewed several of the five Condition Reports, some more than four years old, and found no indication that corrective actions recommended in these reports were completed.

33. In addition, in 2005 a sixth CR was written, CR-VTY-2005-02239, stating “CHECWORKS predictive model for Piping FAC inspection program was not updated per appendix D of PP 778028.” *See*, Attachment M. The first page of the CR includes a statement that this condition had no impact on the RFO 25 inspection scope – ie, — indicating that updating of CHECWORKS was not necessary for establishing scope of RFO25. This is another indicator that the VY FAC program was prima facie non-complaint of its CLB.

34. A review of a focused self assessment was performed. This assessment was called for under one corrective action from a Condition Report LO-VTYLO-2003-00327. Numerous issues are identified in this report and required or require action to bring the FAC program into compliance with the CLB. For example, the program susceptibility review report for 2004 was not formal, and did not properly separate scope for ranking. *See*, Appendix N at 17. The report was not given an adequate review, nor placed in the document control system.

35. Plant modifications and inspection results were noted as not updated in PP77028 since May 15, 2000. *Id.* at 18.

36. Ranking of small bore piping was not done. With no ranking, the basis for selection of high susceptible points for small bore piping is not evident. *Id.* Procedural conflicts were identified with missing programmatic requirements. *Id.* at 27.

37. A flow-accelerated corrosion related pipe break associated with a 1” elbow, SSH (WO 06-6880), appears to have occurred in 3<sup>rd</sup> quarter 2006. *See*, Attachment J at page NEC 038041.



38. Entergy apparently reduced the number of FAC inspection data points between the 2005 refueling outage and the 2006 refueling outage, in violation of its commitment to *increase* inspection data points by 50%. The 2005 refueling outage inspection called for 137 large bore inspection points. The 2006 refueling outage inspection, presented to the ACRS on June 5, 2007, covered only 63 points. *See*, Advisory Committee on Reactor Safeguards. *See* Attachment K, Subcommittee on Plant License Renewal.

39. The 2006 refueling outage FAC inspection scope, planning, documentation, and procedural analysis all appear to have been performed under a superseded program document. ENN-DC-315 Rev.1 was effective March 15, 2006, superseding the PP7028 Piping FAC Inspection Program. *See*, Attachment O. Yet VY inspection plan for FAC Program PP77028 was approved on May 11, 2006, almost two months after the PP77028 program document was superseded. *See*, Attachment G, VY Piping FAC inspection Plan – 2007 Refueling Outage at 1. This error potentially invalidates the baseline requirement of CHECWORKS, in accordance with NRC endorsed guidance, to establish the as-found condition of components and piping. *See*, Attachment D, NUREG 1801 volume 2. Rev.1 page 745 and XI.M17, “Flow accelerated corrosion”. This fundamental step is required in NSAC 202L approach for FAC, and is a required step in the CHECWORKS instructions. Essentially, working to a void procedure makes the results invalid. The baseline for the configuration change as called for in NSAC 202L is to be treated the same as new design. *See* Attachment D. Given the significant changes to the plant, a baseline pass with accurate inputs was necessary, and subsequent passes were necessary to establish the grid locations, and high susceptible inspection points.

40. No indication is provided that plant isometrics were updated as required as of 10/22/04. *See*, Attachment N at 19.

**V. Time needed to benchmark CHECWORKS for Post-EPU use at VYNPS**

41. I agree with the testimony of Dr. Joram Hopenfeld in his Declaration in Support of NEC's Petition to Intervene that CHECWORKS is an empirical model that must be updated with plant-specific data. NUREG 1801 does not specify the number of years of data that are necessary to benchmark CHECWORKS, but does advise that a baseline must be established as noted above. This is reasonable given that each plant has unique characteristics and operating history. Separate industry guidance supports 5-10 years of data trending. *See eg*, Attachment P, Chockie Group International, "Aging Management and Life Extension in the US Nuclear Industry" (October 2006) at 38 ("In order to establish a baseline the operating history of the plant's equipment performance and reliability over the past 5-10 years is reviewed and trended"). Trending to the high end of the range is appropriate where variables affecting wear rate, such as flow velocity, have significantly changed, as at VYNPS following the 120% power up-rate.

42. Given the deficiencies in the current VYNPS FAC program discussed in this Declaration, trending under this program is of marginal value.

43. I disagree with the assertion made in paragraph 38 of the Joint Declaration of Jeffrey S. Horowitz and James C. Fitzpatrick In Support of Entergy's Motion for Summary Disposition of NEC Contention 4 that a prolonged period of data collection is not necessary to use CHECWORKS effectively at VYNPS after the 120% power uprate because the predictive algorithms built into CHECWORKS are based on FAC data from many plants. VYNPS is unique in its approach of CPPU in its uprate to 120%. Clinton is the only other plant to accomplish a one step uprate to 120% power and is a very different plant from VY. To my knowledge, out of 102 operating plants only six have increased

operating power by more than 15%. Of this group, at least three – Clinton, Dresden, and Quad Cities – appear to have FAC related issues. *See*, Attachment G. The argument that CHECWORKS incorporates relevant industry data is difficult to accept when so few plants are operating under analogous conditions, and 50% of those have experienced FAC related problems.

44. It is my opinion that approximately 7 or more cycles will be necessary to establish a credible benchmarking of CHECWORKS to VYNPS under up-rated operating conditions. This benchmarking would begin after the HWC project is complete, and dissolved oxygen in the relevant systems is at stable conditions and well above industry lower limits. It is also my opinion that this can only be accomplished after the current program deficiencies are corrected and a proper baseline is established.

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

Executed this 16th day of July, 2007 at Westville, Connecticut.



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Ulrich Witte

**Ulrich K. Witte**

71 Edgewood Way  
Westville, Connecticut 06515  
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Mobile: 860 391 1183

**Summary:**

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Over twenty-six years' of professional experience in engineering, configuration management, licensing, regulatory compliance of large scale commercial nuclear facilities. This includes management and implementation of design change control programs, engineering standards programs, multi-department/multi-functional licensing initiatives, plant design basis and engineering process improvement programs for six energy companies operating seven nuclear power plants. Responsibilities include:

- Systems solutions to plant operations, engineering modifications, safety analyses, design changes, installation and testing, software, drawing change programs, and training. Optimized function interfaces to insure proper coordination and synchronization for cost effective and compliant operation of the facility.
- Technical support management, and issue resolution programs that identified potential hardware, operational or equipment function issues, as well as document problems, data management problems and organizational enhancements
- Engineering Change Processes from change inception to document close-out
- Multi-department Configuration Management Program including technical approach, consensus, approval, and implementation. Managed a standing Configuration Management Programs Group whose goal was to integrate ten functional areas under a corporate strategic plan encompassing two nuclear facilities.
- Vertical slice system design/operation reviews, design bases / regulatory rule reconciliation, and licensing bases reconstitution and transitioning projects
- Integration of plant equipment information systems with business processes within engineering, materials management, maintenance, and plant operations.
- Structured business process modeling. Application of functional analysis purely from a data prospective—to enhance change management, efficiency.
- Chaired ANSI certified industry guidance on cost effective, compliant, and institutionalized programs for successful configuration management enhancement
- EPRI guidance on optimizing the Engineering Change Process
- Formal training to engineering department personal with specific courses on the engineering change process, plant safety analysis, and modification testing. Trained engineering personal on the requirements of the plant wide Configuration Management Program.

### **Technical Consultant**

Northern Lights Engineering, L.L.C., 71 Edgewood Way, Westville, Connecticut 06515 (May 2002 –Today)

Established a consulting practice where I provided expertise in matters affecting the safe operation and regulatory compliance of commercial nuclear power facilities. This includes licensing and regulatory compliance issues, modification and implementation of industry standards, engineering design reviews, and configuration management analysis associated with an unexpected event, a design failure, or an elevated risk condition, and includes review of proposed changes to the plant operating license in preserving design efficacy.

#### Technical Advisor and Expert Witness to the law firm of Shems, Dunkiel, Kassel, & Saunders, PLLC

Currently providing technical assistance in prefiled testimony regarding Entergy Nuclear Operations application for renewing the operating license of Vermont Yankee. This includes the Aging Review Management Program, in particular flow-accelerated corrosion issues, and finite element fatigue analysis reviews of susceptible components and a number of other contentions related to the safe operation of the plant beyond its 40 year license at 120% of original design power.

#### Technical Advisor, to the law firm of Leroche, Meyers, and Conswel, LLP.

Provided licensing and regulatory compliance expertise in legal claim and derivative action by the board of directors of the First Energy Corporation against its corporate officers in their role associated with the Northeast black out of August 2003, and the mismanagement of the Davis Besse Nuclear Power Plant.

#### Technical Advisor to the Union of Concerned Scientists

Provided technical review of UCS analysis of the Davis Besse reactor head corrosion event. This included analysis of the loss of integrity of the reactor vessel, and the immediacy of the reactor head failure.

### **Senior Scientist, Dominion Resources Inc, Millstone Station:**

P.O. Box 128, Waterford, Connecticut 06385-0128 (December 1996 – 2002)

Project Manager, Licensing Commitments. Established the Regulatory Commitment Management Program. Developed a program that established senior management and department level control of more than 30,000 licensing commitment that was previously broken. The substantially enhanced program captured, dispositioned, consolidated, and managed implementation of docketed commitments to the NRC. Status, responsibility and clear communication were successfully implemented to allow Millstone to successfully restart Units 2 and 3.

The effort required substantial procedure revisions, customer consensus building, and integration of separate free-standing department specific database applications, as well as the station wide action item tracking system. A near term deliverable necessary for the successful restart of Unit 3 was to provide a workable, compliant and functioning regulatory commitment management program.

Project Manager, 50.54(f) Licensing Bases Transition Project. I led a team of 14 individuals to disposition and validate approximately 5100 regulatory commitments necessary for restart of Unit 3. The effort has led to a quality rate of more than 98 percent with production average of about four hours per commitment.

### **Manager, Configuration Management Program, New York Power Authority:**

123 Main Street, White Plains New York 10621, Nuclear Generation Department, Engineering Division  
(November 1991 - November 1996)

Established the Configuration Management Program for the New York Power Authority's nuclear facilities. Included are 10 functional areas and integrated controls as authored in the corporate strategic plan. Management functions and technical skills include the following:

- Established Configuration Programs Group. This group and my position were established as a result of INPO Plant Evaluation calling for configuration management enhancement, and resolution of design control issues identified by the NRC in their DET Inspection of 1991 of the FitzPatrick Plant, as well as independent assessments. Recruited permanent staff, and supplemented the group with contracted staff on as needed basis to support both plants.
- Modified the engineering change process. Areas of immediate attention included the Design Control and Modification Programs, where a series of working groups were established to correct technical content and improve quality, ownership, and business efficiency of the design change process. This effort was achieved via: (1) a formal process to assess, model, and enhance the design change and modification process and interfaces to key functions; and (2) immediate changes to engineering procedures.
- Assessed and enhanced the Plant Equipment Data Base and controls for each plant. Results of the assessment indicated that the IP3 Plant Equipment Database contained significant problems with component classification, equipment type and status, maintenance history etc. Prepared and implemented a recovery plan and project team to reestablish the controls and content of database to be compliant with NRC Generic Letter 83-28 and to support the plant restart. Streamlined and enhanced the component classification process for both plants. Established controlled and non-controlled segregation of plant equipment in accordance with recent EPRI guidance.
- Automated and validated existing fragmented and corrupt sources of engineering information. These data sources were compiled, validated, and controlled and included multi-department areas such as set point controls, Electrical Cable and Raceway Information Systems for JAF and IP3, along with the fuse controls and data management.
- Developed design basis problem resolution process, "Design Document Open Item". Established methods for prioritizing, tracking and closing out design document issues. Established proper interface and control room notifications as per tech spec requirements. Provided guidance on operability determinations and reportability. Provided oversight for classifying and tracking more than 1100 open design issues for IP3 and 300 for JAF. Defended program to the NRC.
- Established working groups between Nuclear Generation Department and the corporate wide Information Management Organization. Gained management endorsement for areas of data quality improvement and automation for the Nuclear Generation Department. This led to enhanced implementation of the equipment information systems for both sites.

### **Project Manager, Program to Assure Completion and Quality, Tennessee Valley Authority:**

(December 1990 - March 1991) Under contract by CYGNA Energy Services to the Vice-President, Engineering and Operations Department, Watts Bar Nuclear Plant.

- Developed a comprehensive plan to measure progress and confirm quality of the in-progress design evolution of the plant. Developed a methodology for linking specific plant equipment to that equipment's respective design basis (and associated design attributes); license commitments; and numerous verification programs currently in place. The five phase program was presented to NRR in January and received approval as an activity to assist TVA in removing the stop work order on construction of the facility.

### **Technical Manager, Configuration Management Program, Southern Nuclear Operating Company:**

(December 1988 - November 1991). Under contract by ABB Impell and CYGNA Energy Services to Corporate Engineering Manager, Edwin I. Hatch Nuclear Plant, Georgia Power Company.

- Established and implemented the Hatch Configuration Management Program. Phase one of the effort included definition, establishment of management objectives, specification of the configuration management program scope and development of a reference manual.
- Developed and executed formal rigorous horizontal evaluations (the second phase of the project) of each relevant functional area including engineering design, implementation, plant operations and maintenance, procurement, information systems, document control and others. The program integrates functional areas across the plant, each architect engineer, and corporate (SONOPCO and Southern Company Services) organizations.
- Implemented enhancements to the program. This phase includes upgrading the design change process to achieve successful integration across organizations; stricter adherence to closure activities; and formal design engineering involvement in such activities as procurement of replacement items (equivalency). Additional controls were established such that misapplication of information obtained through informal design change processes such as the "Request for Engineering Assistance".
- Reconciling the plant's design basis. A second major activity of the program was to compile, consolidate, and ultimately, automate the plant's design basis. A major objective is to provide access and retrievability of current design basis to each of the key users of each participant organization.
- Applied Structured Business Analysis including CASE tools in the evaluation and enhancement phases. The as-found configuration management activities of all relevant processes were modeled and analyzed with this technique. Proposed enhancements are then tested on the model prior to actual implementation.
- Chaired the subcommittee for the Nuclear Information and Records Management Association which is developing a Technical Position Paper entitled, "Implementation of a Configuration Management Enhancement Program for a Nuclear Facility".

### **Team Leader, NRC Safety System Functional Inspection Response Organizations:**

Led the NRC Safety System Functional Inspection Response Teams for Georgia Power Company (1989), and Sacramento Municipal Utility District (1987). Assisted as team coordinator in the GPC - Plant Hatch Electrical Distribution System Functional Inspection Response Team (1991). Under contract by ABB Impell (December 1987 - November 1990) to the site Engineering Manager, Rancho Seco, SMUD. and CYGNA Energy Services (December 1990 - November 1991) to the Corporate Engineering Manager, Edwin I. Hatch Nuclear Plant, Georgia Power Company.

- In the case of GPC, the NRC SSFI resulted in validation of the in progress implementation of the Hatch Configuration Management Program, and only one violation to the licensee.
- The effort included an SSFI self-assessment as well as managing the utility through the NRC inspection.
- For SMUD, developed and executed a plan for closure of both immediate findings and long term corrective action required. Assisted in defending the plan to the NRC.
- For GPC - Plant Hatch EDSFI in June 1991. Developed and implemented an EDSFI Preparation Plan for the Engineering (both A/Es) and site organizations. This effort included management of a 27 man team preparation and inspection response team for the Hatch EDSFI.



### **Deputy Mechanical Engineering Manager, Engineering Department**

Under Contract to the Site Engineering Manager, Rancho Seco, Sacramento Municipal Utilities District, Rancho Seco (April 1986 - September 1987)

Managed the implementation and closure of over 400 modifications to the plant. Provided the NRC with a basis for allowing a successful restart of the facility. (January 1986 to November 1986) Impell Lead Project Engineer, Class 1 Piping and Support Recertification Effort, SMUD.

- Developed an engineering department action plan to improve technical quality, reconstitute design basis for five systems, control costs of plant modifications, and improve adherence to schedule.
- Responsible for the complete recertification of the Pressurizer Relief Line, Decay Heat System, and others. Responsible for expediting and implementing design changes as necessary through to closure. Assisted in Utility responses to NUREG-0737, and I&E 79-14.
- Upgraded the Engineering Department procedures to gain credit for the relaxation of ASME code requirements in structural damping values. Initiated the FSAR changes as well.

### **Project Engineer, Fire Protection:**

Under Contract to Sacramento Municipal Utilities District, Rancho Seco ( November 1984 to April 1986), SMUD Fire Protection Coordinator, Fire Protection Program

- Developed the SMUD Appendix R Fire Protection Program. Established or substantially revised 110 plant and engineering procedures including shutdown procedures on total loss of the plant's control room, technical specification surveillance procedures, fire protection system maintenance procedures, and the development of a fire protection program manual.

Successfully defended the program to the NRC during the 1985 Appendix R Inspection, with no resulting findings or open items.

### **Additional Experience (6/78 through 8/84):**

Senior Engineer, performed original pipe stress analysis and support placement for Duke Power's Catawba Plant. Qualified approximately 8 class one and two plant systems. (ABB Impell 6/78 - 12/79).

Non-linear finite element analysis of large diameter piping for EPRI. Analysis of production stress codes versus non-linear evaluation techniques, versus actual in situ testing of the system. Results were published in EPRI Report "Seismic Piping Test and Analysis. (ABB Impell, 1980 -1981)

As Project Engineer, directed the preparation of the annual Emergency Plan exercises for Kansas Gas and Electric Company, Union Electric Company, and Texas Utilities. In two plants, the exercise was installed on the plants simulator, and received recognition from the NRC for realism of the scenario. (ABB Impell 1982-1984).

### **EMPLOYER SUMMARY:**

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71 Edgewood Way  
Westville, CT 06515

12/2002 – current

**Northeast Utilities /Dominion Resources Inc** 12/1996 – 12/2002  
(Under Contract via Cataract Inc through 9/97.)  
2500 McClellan Ave.  
Pennsauken, NJ 08109

**New York Power Authority** 11/1992 - 12/1996  
123 Main Street  
White Plains, New York 10671

**Cygna Energy Services** 11/1991 - 11/1992  
5600 Glenridge Drive, Suite 380  
Atlanta, Georgia 30075

**ABB Impell Corporation** 6/1978 - 11/1991  
333 Research Court  
Technology Park-Atlanta  
Norcross, Georgia 30095

### **EDUCATION:**

University of California, Berkeley  
B.A. Physics, 1983  
Senior level and graduate course work in Mechanical Engineering, and Electrical Engineering

Quinnipiac University School of Law  
J.D expected June, 2009

### **PUBLICATIONS:**


- EPRI Report Number 108736, "Guidelines for the Optimization of the Engineering Change Process," March 1994.
- NIRMPP-03, "Position Paper for a Configuration Management Enhancement Program for a Nuclear Facility," April, 1992. Subcommittee Chair.
- EPRI Report Number 8480, "Seismic Piping Test and Analysis," 1980.

### **PROFESSIONAL AFFILIATIONS AND AWARDS**

American Society of Mechanical Engineers, American Nuclear Society, Nuclear Information and Records Management Association, Who's Who For Rising Young Americans.

### **REFERENCES:**

References available upon request.

	<p>QUALITY ASSURANCE DIVISION VERMONT YANKEE NUCLEAR POWER PLANT</p>
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AUDIT NO.: QA-8-2004-VY-1

TITLE: Engineering Programs

ACTION ORGANIZATIONS:

Design Engineering  
System Engineering

AUDIT TEAM:

B. E. Hall, ENNNY/QA,	ATL
H. Heilman, ENNNY/QA	ATM
Nick Love, Constellation	Tech Specialist

AUDIT DATES: 9/20/04 - 9/30/04Exit: 10/07/04

PREPARED BY:

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APPROVED BY:

Thomas P. White 11/22/04 *Thomas P. White*  
Quality Assurance Manager / Date

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EXECUTIVE SUMMARY

The audit team concluded that the four engineering programs evaluated during this audit, Reactor Vessel Internals, Check Valve, Relief Valve, and Environmental Qualification Programs were effective and were being administered and maintained in a manner that meets regulatory requirements/commitments and supports safe and reliable plant operation.

The team concluded that while the Flow Accelerated Corrosion Program was technically sound, a number of the administrative/documentation issues identified did not meet regulatory requirements.

The following table summarizes results for evaluated elements:

Elements	Result	Number of CRs/AFIs
EQ Program	Satisfactory	2 CRs 2 AFIs
Check Valve Program	Satisfactory	ICR 3 AFIs
Flow Accelerated Corrosion Program	Unsatisfactory	2 CRs
Relief Valve Program	Satisfactory	1 CR 1 AFI
Reactor Vessel Internals Program	Satisfactory	ICR 1 AFI

Overall Results

The audit team identified five findings, two compliance CRs, and seven areas for improvement. None of the findings or areas for improvement, individually or in the aggregate, were indicative of significant programmatic weaknesses which would impact the overall effectiveness of the Engineering Programs assessed. However, as previously noted, there were administrative / documentation issues with the Flow Accelerated Corrosion Program which need to be corrected.

Findings

RFO 24 FAC documentation not yet completed.  
(CR-VTY-2004-03061 Cat C – Design Engineering M&S)

QA records not handled in accordance with procedures.  
(CR-VTY-2004-03062 Cat C – Design Engineering M&S)

Multiple versions of MOVATS software in Check Valve Program.  
(CR-VTY-2004-03087 Cat C – System Engineering Components)

Relief valve as-found testing near miss.  
(CR-VTY-2004-03039 Cat B – Work Control)

QDR 8.6 does not clearly document how Amphenol connectors with Rexolite are qualified.  
(CR-VTY-2004-03032 Cat C – Design Engineering EI&C)

## Compliance

LO-CA issued instead of CR during IVVI Self-Assessment.  
(CR-VTY-2004-03086 Cat D – System Engineering Code Programs)

Master EQ List references deleted QDR 8.9.  
(CR-VTY-2004-03106 Cat D – Design Engineering EI&C)

## Areas for Improvement

LO-VTYLO-2004-00512

- CA - 1 The following documents need to be updated: OP 4223 needs to reflect new equipment, software, and practices. Vendor Manual VYEM 0250 needs to be evaluated to determine if it should be retained and updated or deleted.
- CA - 2 ESP training activities should be developed for the Check Valve Program similar to those for the MOV/AOV Program
- CA - 3 Submit VYAPF 0700.03 to training to get training credit for the two component engineers who completed off-site check valve diagnostic training.
- CA - 4 A maximum and minimum examination distance for the camera is established at the time of resolution demonstration check. Each examination record should indicate the distance the camera was from weld or verify that the camera was within the resolution range. The distance of the lens to the examination surface cannot be determined from the current QA records.
- CA - 5 The relief valve scheduling spread sheet should use the installation date rather than the as-found testing date to schedule the next test since the as-found test can be performed up to 90 days or one year after the valve is replaced. This can lead to incorrect due dates for the 48 month interval and the ten year mandatory test dates.
- CA - 6 The EQ Health Report should include all outstanding corrective actions related to EQ, not just those assigned to the EQ Coordinator. The current EQ Health report indicates no corrective actions are outstanding against the program. However, there are open corrective actions open to other departments for EQ issues. (CR-VTY-2001-00983 "EQ MCC Component Replacements Not Performed by End of EQ Life," Corrective Actions 1,4,8,9, 13)
- CA - 7 The EQ Coordinator should note in the program health report the OEs that he had seen during the period of the report. Currently if no actions are taken there is no documentation that he has reviewed any OEs.

AUDIT PURPOSE, SCOPE, AND METHODOLOGY

## Purpose:

The purpose of this audit was to determine whether selected Engineering Programs have been adequately maintained and administered to effectively meet regulatory requirements/commitments and support safe and reliable plant operation.

## Scope:

The selected engineering programs included the Environmental Qualification (EQ) Program, the Check Valve Program, the Flow Accelerated Corrosion (FAC) Program, the Relief Valve Program, and the Reactor Vessel Internals Program. Each program was checked to verify that it was being maintained current, that software used by the program was current and in the SQA program if applicable, and that required inspections/surveillances have been identified and implemented. In checking that the program was current, the impact of design changes, Extended Power Uprate (EPU), regulatory changes, deviations from codes and standards, industry positions, and industry experience was considered.

## Methodology:

The audit was performed through interviews with engineering personnel and others as appropriate and through the examination of procedures and documentation.

AUDIT DETAILS

## Program Maintenance / Instructions, Procedures, Drawings

## Plant Modifications

The audit team members concluded that adequate programmatic "hooks" existed to ensure that program engineers would be included in reviews of design changes affecting their programs and that programs have been adequately updated to reflect design changes. There was an exception noted in the EQ Program which is discussed below.

## Environmental Qualification

During a review of several Qualification Documentation Review (QDR) Packages, it was noted that inboard electrical penetration Amphenol connectors were included in the Victoreen HRRM Package (QDR 8.6). The qualified life of these connectors was identified as 2.61 years. During a review of work orders to verify that the connectors had been replaced at the required frequencies, it was determined that new connectors were evaluated for this application per Equivalency Evaluation (EE) 1101. QDR 8.6 had not been adequately updated to reflect the new component with a longer qualified life. EE-1101 was considered inadequate because it did not reference the test report, a 10CFR50.49 requirement, needed to qualify the new connectors to IEEE-323. Thus, EE-1101 did not provide for an adequate evaluation of a critical characteristic for this EQ application. The EQ Program owner was unaware that these connectors had been replaced with a longer life component and wrote CR-VTY-2004-03032 to document the issue. An operability determination concluded that this issue was not an operability concern. This modification was not recent and changes made to the EE process should preclude recurrence.

The auditor also noted during the QDR reviews that the EQ Master List still referenced QDR 8.9.1 which had been previously deleted. CR-VTY-2004-03106 documented this issue.

#### Check Valve Program

Based upon a review of ENN and VY procedures, the auditor verified that the responsibilities of the Check Valve Program Coordinator (CVPC) included a review of plant design changes involving the addition, deletion, or change in station check valves. Although the CVP was not specifically included on the distribution of pending design changes, Component Engineering and/or the 1ST Coordinator were. Based on a discussion with the 1ST Program Coordinator, he has a good working relationship with the CVPC for interface of all aspects of the two programs. The review of design changes for program impact was discussed with the CVPC who stated that he would be included for review if a check valve was affected. He was included in the review of the EPU design change which added a third safety valve (he is also the Relief Valve Program Coordinator).

#### Flow Accelerated Corrosion

Section 3.2.12 of PP 7028 identified that one of the responsibilities of the FAC Inspection Program Coordinator is to "update/maintain the 'FAC Susceptible Piping Identification' document to reflect plant changes as required." Section 0.5 requires revision of the CHECWORKS module to reflect current plant design and operation. AP 6008 requires the Mechanical & Structural Group to review all VYDCs. AP 0020 also requires MMs to be reviewed by Mechanical & Structural unless it is checked NA for their review.

#### Relief Valve Program

Procedures PP 7204 and OP 4261 for 1ST and BOP valves include notes relative to changes to the program and equipment and the associated reference to the design document.

One pending change to the Safety & Relief Valve (S&RV) Program under ER-04-1222 was not routed to the program engineer for required review; however, the 1ST Engineer was a required reviewer for the change. The S&RV Program Engineer became involved when questioned on the need for pre-installation setpoint verification and provided input to the change originator by e-mail on 09/22/04. This omission was discussed with the originator who assumed that 1ST was the proper individual to respond. A further review revealed that ENN-DC-115, "ER Response Development," includes Programs and Component Engineering for impact screening. This appeared to be a misunderstanding and not a programmatic issue.

The auditor verified that procedure OP 4201 was revised by Maintenance Support to reflect the addition of a third safety valve installed for EPU.

Both procedure changes had the required documentation packages with approvals retained in Curator.

#### Reactor Vessel Internals Program

The Reactor Vessel Internals Program is driven primarily through the implementation of Procedure PP 7027, which maintains the inspections and examinations that are required under the BWRVIP Program. Although there are no current plant modifications that would affect this program, steam dryer cracking was being evaluated for scope increase. This was based upon the industry issues involving steam dryer cracking and the VY steam dryer cracks that were identified and repaired during RFO 24.

## **Extended Power Uprate**

Section 10, of Volume 2 of the "Vermont Yankee Nuclear Power Station Extended Power Uprate BOP Engineering Report" addresses the impact of the Extended Power Uprate (EPU) on various programs. Four of the five programs selected for this audit were addressed explicitly in section 10. The auditor considered that the fifth, Safety & Relief Valve was implicitly addressed as part of the IST Program. Based upon reviews of these sections and discussions with the program engineers, the auditors concluded that the impact of the EPU on Engineering Programs was being adequately addressed.

## **Environmental Qualification**

Due to temperature and radiation increases during accident scenarios, 181 pieces of equipment would need to be requalified and 1 modification was required. The EQ Coordinator stated that he was actively working on completing the required requalifications. As a check the auditor reviewed QDR 6.14, Rome XLPE/PVC Cable, which would be impacted. This review found the manner of evaluating qualification for radiation dose to be adequate and appropriate to assess increased dose from the power up-rate. No issues were identified with EPU impact.

## **Check Valve Program**

The main impact of the EPU would be on feedwater flow, steam flow and the generator. The report concluded that there would be no programmatic effect on the Check Valve Program, but that degradation rates could be affected by the EPU. Although it concluded that the normal inspection process should be adequate to identify changes in the valve degradation rate, it recommended that the program coordinator review the parameter changes caused by the EPU to identify any recommended testing or inspection frequency changes. The Check Valve Engineer has requested information on any velocity changes resulting from the EPU for further consideration of PM changes. The auditor had no further issues.

## **Flow Accelerated Corrosion**

The impact on the FAC Program of changes in the temperature, pressure, and velocity due to the power uprate were considered. Based upon evaluations of individual system impacts, it was concluded that there would be minimal impact on FAC and that no additional systems would need to be added to the FAC Program. The report also recommended new CHECWORKS runs to identify possible changes in FAC concerns (increased erosion rates, reduced useful components life, etc.). The new flows will be included in the new CHECWORKS model once version 1.0G is approved.

## **Relief Valve Program**

The EPU impact on the IST Program would be evaluated as part of the EPU change process. Modifications/changes are evaluated as part of the modification process for changes in system/component design requirements.

The Safety & Relief Valve Engineer indicated that he had been involved with EPU changes and had reviewed the design change packages. He has been satisfied with the interface between himself and the EPU staff. Pending procedure changes have been made to reflect the modifications made during RF024.



### Reactor Vessel Internals Program

The report noted that the In Vessel Visual Inspection (IVVI) Program was revised prior to each refueling outage. Since the EPU would be implemented following an outage, the program update prior to the outage should include any required EPU information [Dryer inspections and repairs were completed during RFO 24]. GE Task Report T0302, "Reactor Vessel Integrity Stress Evaluation," evaluated the expected EPU stress in many components/locations.

The auditor obtained and reviewed a copy of the "Licensee Identified Commitment Form" in accordance with ENN-LI-106, which demonstrated that a process was in place for preparing an action plan for the monitoring of the Steam Dryer. This document outlined a number of one-time commitment actions relative to the analysis, inspection and reporting actions and their respective scheduled completion dates. It was noted that several of the commitment actions had near term completion dates as well as indeterminate dates. A search of LOCRs using a key word of "steam dryer" showed that LOCRs had been written to track various steam dryer requirements.

### Regulatory Changes

The auditors concluded that regulatory changes were being adequately addressed. No issues were identified by the auditors.

### Environmental Qualification

There have been no recent regulatory changes impacting the VY EQ Program.

### Check Valve Program

Regulations mandating elements and testing of the Check Valve Program are Technical Specifications, the 1ST Program, and ASME OM-1998 Edition through ASME OMB-2000 Addenda. The Check Valve Program procedure has been revised for the new code requirements of the 4<sup>th</sup> 1ST interval.

### Relief Valve Program

Current 4<sup>th</sup> interval 1ST requirements for test frequency and expansion testing have been included in the Program procedure, PP 7204, "Safety & Relief Valve Program." Procedures have been revised to reflect the correct codes for the 4<sup>th</sup> 1ST interval.

### Reactor Vessel Internals Program

Program procedure PP 7027 "Reactor Vessel Internals Management Program" was reviewed, and was determined to address the necessary requirements for adequately implementing the BWRVIP Program. The procedure provides the necessary direction for the responsible individuals to review and initiate actions that may be required upon the issuance of NRC correspondence, information notices, BWRVIP documents and G.E. bulletins, etc., as they apply to Vermont Yankee. In turn, the information obtained from these documents is incorporated into the various inspection plans that are implemented during refueling outages.

To determine the adequacy of the prepared inspection plan, a comparison between PP 7027, Appendix A "Reactor Vessel Internals Components Inspection Scope and Schedule" and the RFO 24 Reactor Vessel Services In Vessel Visual Inspection Final Report was performed. Both were obtained from Curator. A sample of activities was randomly selected from the RFO 24 schedule, with respect to the method of examination and the relative frequency of the examination. These activities were compared with the RFO final report to determine if the appropriate examinations were performed. In all instances reviewed, the report confirmed that the required examination method and frequency were correct. In several instances, due to limited accessibility of the examined component, a partial examination was performed and documented as such. The assessor had contacted the Site Reactor Internals Engineer, to ascertain whether or not the examination sufficiently evaluated the component under examination. The engineer indicated that the inspection of the accessible portion of the component revealed no recordable indications, and was therefore deemed acceptable until such time that the reactor internals are accessible due to disassembly. The auditor subsequently confirmed that Technical Justification No. 2004-02, dated March 26, 2004 was issued for the deferral of inspection of inaccessible welds and Technical Evaluation No. 2004-0018 dated April 2004 addressed inspection of portions of shroud horizontal welds.

#### Code and Standards Deviations

Deviations from codes and standards, where applicable, have been adequately addressed. No issues were identified by the auditors.

#### Environmental Qualification

Based on discussion with the EQ Program owner, VY has not requested any deviations from NRC EQ Program requirements.

#### Check Valve Program

The Check Valve Program does not have deviations from approved codes and standards but implements and tracks deviations developed and approved under the 1ST Program. Several changes which were noted to valve testing/inspection frequencies were verified to be addressed with document changes, PM Basis Database changes, and EMPAC Asset schedule changes.

Changes from regulatory standards relative to the 4<sup>th</sup> interval 1ST Program and implemented or tracked through the CVP have been approved under NRC Letter NRY 03-078.

#### Flow Accelerated Corrosion

By letter dated March 19, 2001, VY requested approval from the NRC to use Code Case N-597 which was an alternative approach to evaluating components when the section thickness has been reduced below code minimum thickness. NRC approval was received by letter dated July 21, 2001.

#### Relief Valve Program

The 1ST 4<sup>th</sup> interval code deviations have been approved and accepted under NRC Letter NRY 03-078. The auditor verified that procedure OP 4201 referenced the proper codes for the 4<sup>th</sup> 1ST interval.

### Reactor Vessel Internals Program

Based upon spot checks the auditor confirmed that exceptions made due to weld accessibility and deferrals were documented and justified.

### Industry Alignment

In general, the auditors concluded that the programs reviewed were acceptably aligned with industry positions. As discussed below, VY's approach to the EQ Program is more fragmented than others, but this was discussed with engineering management who had already recognized some of these issues and was evaluating approaches to resolve them.

### Environmental Qualification

The QDR Packages reviewed had strong technical content and were organized in a manner that made the required information easy to find. This provides a strong basis for the program. Current industry efforts are focused on internal communications and retention of configuration control.

Based on review of procedure ENN-LI-100, ENN-DC-115 and ENN-DC-329, the recent implementation of these procedures at VY would appear to offer some enhancement to the oversight and feedback available to program owners. This may mitigate some of the potential for future disconnects between the maintenance organization's component replacements and engineering's oversight responsibilities.

However, these procedures which impact the EQ Program are partitioned in a manner that fragments program oversight accountability between licensing, engineering, and maintenance. ENN-LI-100 makes no reference to the EQ Program and ENN-DC-115 is a classification and screening process for engineering aspects only. The applicable procedures, including VY AP's offer only very limited flow charts identifying how the programs processes are supposed to work or how the various parts of the organization interface with each other. These issues were discussed with Engineering management.

Program health is a significant aspect of the INPO EQ Program Guideline currently in preparation. Audit health reports for quarter 2003-Q4 and 2004-Q1 were reviewed. The 2004-Q1 report indicates no CR CA's open against the EQ Program at this time. In fact, this is because the applicable performance indicator has been interpreted to apply only to CR CA's assigned to the EQ Program owner as opposed to those impacting the program as a whole. The industry position would be that the health report is intended to capture full program scope at the plant. CR-VTY-2001-0983 has five open items against it relating to non-performance of EQ component replacements. This issue was documented as CA6 of LO VTYLO-2004-00512.

### Check Valve Program

This scope element was discussed with the Check Valve Engineer. The program was originally developed based on the industry documents as identified in the program procedure purpose section and references. The review and inspection processes used in the development of the program are documented in curator under SOER 86-03. Corrective maintenance is factored into the program and subsequent PMs revised based on findings. Additional balance-of-plant check valves which were considered a risk to generation, but were not originally covered in the SOER 86-03, have also been included in the program. Based on a review of the type valves tested, the test methods, maintenance, intrusive and non intrusive inspections, the program and test methods appear to be in alignment with industry expectations.

### Flow Accelerated Corrosion

Surveillance 99-016 verified that the VY FAC Program met both NRC expectations and industry guidelines as defined in Generic Letter 89-08, "Erosion/Corrosion - Induced Pipe Wall Thinning

Program uses CHECWORKS, an EPRI sponsored code, as a tool for prioritizing inspections and tracking data. VY also participates in CHUG, an EPRI sponsored CHECWORKS user's group.

### Relief Valve Program

The S&RP was developed based upon EPRIINMAC guidance with recommendations from INPO included for balance-of-plant valves. The inputs and methodologies used in the development are discussed in the procedure as a historical reference. There have been no new initiatives in the area that are not included in the current program.

### Reactor Vessel Internals Program

Program procedure PP 7027 "Reactor Vessel Internals Management Program" was reviewed, and was determined to address the necessary requirements for adequately implementing the BWRVIP Program. The procedure provides the necessary direction for the responsible individuals to review and initiate actions that may be required upon the issuance of NRC correspondence, information notices, BWRVIP documents and G.E. bulletins, etc., as they apply to Vermont Yankee. In turn, the information obtained from these documents is incorporated into the various inspection plans that are implemented during the respective refueling outage.

During documentation reviews, it was noted that it could not be determined how the IVVI examinations were conducted, with respect to the measured distance between the lens of the camera and the examination surface. Procedure NE 8048, Rev. 1, paragraph 4.1.2 states in part, that "...the lens to object distance required to discern the target on the Sensitivity, Resolution, and Contrast Standard (SRCS) becomes the maximum distance examinations can be performed from the examination surface." Although the distance/range of the camera lens to the examination surface is determined and documented during the sensitivity, resolution and contrast standard, it cannot be readily determined how the distance is determined/maintained during actual visual examinations. This was addressed in CA 4 of LO VTYLO-2004-00512.

### Industry Events

All of the program engineers were receiving OE relevant to their program and were aware of significant industry events involving their programs. The auditors concluded that industry events were being adequately addressed.

### Environmental Qualification

As a part of the program health assessment, industry operational experience (OE) and NRC Information Notices (IN's) are to be screened for EQ Program impact. A sample of four recent OE's and three NRC IN's with potential EQ Program applicability were submitted to the Technical Support OE Coordinator to determine specifically how they had been addressed. All of the IN's were found in the Technical Support files with documentation to address the extent of their VY applicability including two which were evaluated to actually have direct EQ impact. One of these was entered in QDR 8.6 to address its specific applicability at VY.

Of the four OE's, all were distributed. Two were recognized as having potential EQ impact and sent to I&C/Electrical. None of the IN's and OE's reviewed by the auditor originated during the most recent two health report periods. However, while five additional OE's were issued during the 2003-Q4 and 2004-Q1 periods, none are noted as having been reviewed in the health reports. In discussions with the EQ Coordinator, he indicated that he does not normally identify OEs that he reviewed unless they required action. If no actions were taken, he does not document that he has reviewed the OE. The auditor recommended identifying in the program health report the OEs that he had reviewed during the reporting period even if no action was required. This was documented as CA 7 of LO VTYLO-2004-00512.

The EQ Program owner was very knowledgeable of industry events, and of the general applicability of operational experience at other plants to VY equipment.

#### Check Valve Program

The CV Program Engineer receives OE from the Entergy OE distribution as well as the System EPIX Coordinator. The OE evaluated each quarter is documented on the CV Program Health Report. A review of the last two health reports indicated that twelve OE related to check valves were reviewed. There were no specific changes to equipment, inspections or testing required from the reviews and no commitments resulted.

#### Flow Accelerated Corrosion

Industry events are identified and the bases for performing or not performing additional inspections were documented in the VY Piping FAC Inspection Program PP 7028 - 2004 Refueling Outage." The Coordinator was aware of the details of the piping failure that occurred in Japan and indicated that he has an action item (LO-OEN-2004-00272 CA-00003) to look for similar piping arrangements at VY.

#### Relief Valve Program

OE was discussed with the site OE coordinator, System Engineering EPIX Coordinator and the S&RV Program Engineer. OE that has been reviewed is documented in the Program Health Report. There has been no OE that required specific program changes or commitments generated. However, OP 4200 was revised based upon a concern received from Pilgrim Station involving hydrogen entrapment in the piping downcomer region. The S&RV Program Engineer receives OE for review from the ENN distribution as assigned by the morning screening as well as from the System Engineering OE screener. Seventeen OE reviews were documented in the health report.

#### Reactor Vessel Internals Program

Steam dryer cracking is currently the most significant industry OE issue in this area. This issue will drive further examination of this component in future examination/inspection activities. A Licensee Identified Commitment Form per Procedure ENN-LI-106 was initiated to identify specific actions that will be required to assist in the assessment of this component. This document contained commitments that will incorporate augmented examinations into the Vessel Internals Inspection Program.

#### Software/ Software Quality Control

With the exceptions noted below, the auditors considered that software was being adequately controlled. There were several issues identified with software QA, but none of them directly compromised the integrity of the results.

### Environmental Qualification

VY had EPRI's System 1000 software for materials library reference, but it was not yet in use because it had not been through the SQA Program. The EQ Database, which was developed in 1997, was included in the SQA Program as Level A software. However, the EQ Coordinator indicated that there had been a data corruption problem which IT had been unable to recover. The verified hard copy of the database is considered the Q copy. Since none of the EQ software was being used for Q purposes, this was considered acceptable.

### Check Valve Program

Check Valve Program software is classified as Category A and has been controlled through the procurement process. It has been approved and tested for verification. All paperwork for compliance was available as quality records in FYI.

Multiple versions of MOVATS software (4.6.b and 4.5) were still in use to support older equipment (Maintenance Support lap top computer). SQA paperwork for new versions state old versions are retired. The computer and software should be removed from use or the SQA should be resubmitted to define and allow conditional use of older versions (CR-VTY-2004-03087). Based on discussion with the MOVATS Component Engineer who was involved with all six RFO 24 non-intrusive check valve tests, the MOVATS computer with version 4.6.b software was used to perform diagnostic data collection and analysis.

The ENN web software catalog for VY, which is considered non Q, was not up-to-date for MOVATS software. It listed versions 4.0.0.0, 4.5, and 4.6. As mentioned before, version 4.6.b is the software of record and Curator records show that previous revisions are retired.

Based on discussion with the previous and current CV Program Engineers, one Signature Analysis Module (SAM) notebook computer is not capable of running the newer software. Version 4.6.b is capable of being used with the Viper and UDS systems. A potential area for improvement exists by updating OP 4223 to allow the performance of check valve diagnostics using any of the available systems. This was documented as CA 1 of LO-VTYLO-2004-00512.

### Flow Accelerated Corrosion

The Software QA Program identified CHECWORKS version 1.0F and CHECWORKS Application Manager Version 1.00 as approved software. The FAC Program Coordinator stated that he was in the process of upgrading to version LOG, but had not completed the software QA process. He had been using version 1.0F, but it was approved for a Windows 98 platform which was no longer available. Version LOG supports a Windows XP platform. Once the new version is approved, it can be used to confirm RFO 25 inspection selections and assist in the assessment of EPU impacts. The auditor considered this acceptable.

### Relief Valve Program

S&RV Program 1ST Scheduling software has been controlled and is appropriately classified as Type B in support of Technical Specifications. A review of the software qualification package revealed that all procedural requirements were met and are documented as QA records. No concerns were identified relative to Software QA requirement implementation. For the relief valve scheduling, the auditor noted an area for improvement in the use of the spreadsheet. There are no instructions for the spreadsheet use and currently, the date of as-found testing is inputted instead of the installed date. The as-found test date (performed subsequent to replacement) could cause the next test to exceed the 48 month or 10 year requirement to be exceeded (LO-VTYLO-2004-00512 CA 5).

### Reactor Vessel Internals Program

There were no specific software programs unique to the RVI Program.

### Inspections/Surveillances

The auditors concluded that required inspections and surveillances were being performed, although issues were identified with the completion of documentation in the FAC Program and with a scheduling error which could have led to missing a 90 day requirement in the S&RV Program.

### Maintenance of EQ Requirements

Based upon a review of Qualification Documentation Review (QDR) Packages to determine if adequate end of life replacements are being performed for components with qualified lives of less than 40 years, two examples were identified, one each for QDR's 8.8 and 35.3, where adequate replacements were made for items with qualified lives of 17.6 years and 3.3 years, respectively.

As discussed earlier, the review of QDR 8.6 identified that it had not been appropriately updated following an equivalent component replacement. A review of work orders verified that the new longer life components had been installed in the plant and was therefore not outside of its EQ lifetime.

### Check Valve Program

Required inspections and testing requirements are identified in the program procedure. The performance of the 2004 specified testing was evaluated through the review of 30 EMPAC work orders. All scheduled inspection and testing was performed, rescheduled with appropriate change documentation, or deleted from the 1ST/Check Valve Programs with justification documented. No concerns were noted.

### Flow Accelerated Corrosion

"VY Piping FAC Inspection Program PP 7028 - 2004 Refueling Outage" identified the inspections that were to be conducted during RFO 24. The Post outage report for RFO 24 had not been written at the time of the audit, although the program procedure requires that the report be issued within 90 days. The report for RFO 23, issued on 1/22/02 was reviewed by the auditor and found to be complete, thorough and met the expectations of PP 7028. However, this document had not yet been sent to RIMS. Based upon a search of CURATOR and discussions with the FAC Engineer, it was concluded that a significant amount of FAC Program documentation had not been sent to RIMS. These issues were documented in CR-VTY-2004-03061 and CR-VTY-2004-03062.

### Relief Valve Program

Required testing to meet code or program BOP valve expectations have been defined and tracked in the program procedure. A sample of nine 1ST valves scheduled for testing during 2004/2005 was selected for review. During the review of work orders and the P3 Work Week Schedule for the as-found testing, it was discovered that this activity was scheduled for 02/22/05 which would have been past the 90 day requirement. This had occurred in the past, with 4 CRs written in 2003. The corrective actions from these CRs did not prevent the potential recurrence of the same issue in this instance. CR-VTY-2004-03039 was written to address the near miss.

### Reactor Vessel Internals Program

On a sampling basis, the auditor verified that the scope of examinations/inspections required by the program procedure was performed during the In-Vessel Visual Inspection performed by AREVA. Of the components reviewed, the corresponding requirements were found to be consistent with the scope of work performed. No unsatisfactory conditions were noted.

Personnel certifications were also reviewed to verify that required personnel qualifications were current. All of the individuals responsible for performing the VT-1 and 3 Level II examinations were found to be qualified to perform these tasks during the duration of the RFO, and demonstrated the required visual acuity required to interpret their observations.

Additionally, the auditor verified on a sampling basis, that the individual in-vessel examinations did receive the required sensitivity, resolution and contrast verifications/calibrations. A comparison between the inspection data sheet and the resolution verification log was performed, which confirmed that the necessary resolution was maintained throughout the examination duration. It was observed in some instances, that the individual performing the calibration differed from the person who performed the examination. Upon investigating this concern, it was determined that this practice was acceptable, as none of the key elements of the examination, i.e. water clarity, lighting, nor equipment were affected, which would influence the video image. All of the individuals involved with the examination equipment calibration, performance and interpretation of results were verified to be qualified Level II or higher in the examination method used.

### Self Evaluation and Corrective Action Effectiveness

#### Corrective Action Effectiveness

Based upon a review of the corrective actions associated with the Check Valve and the Safety & Relief Valve Programs, the auditor concluded that corrective actions were acceptable.

#### Check Valve Program

Three QAD CRs that had been generated from surveillances were reviewed to determine if the corrective actions were acceptable, effective, and timely. Equipment issues were also reviewed. One level C and two Level B CRs were reviewed with no issues identified. Overall, CR dispositions were thoroughly performed with corrective actions assigned to address the most probable or apparent causes. Corrective action disposition has been timely with extensions minimal and approvals granted and justified when required.



### Safety & Relief Valve Program

Corrective actions from CRs and recommendations issued as a result of a 2002 QA assessment of the Safety and Relief Valve Program were also reviewed for acceptability, effectiveness, and timeliness. No concerns were identified.

ER-2003-1910 (Level I) for program deficiencies identified during the 2003 NRC PI&R Inspection was reviewed. The root cause investigation was performed to the AP 0009 requirements and commitments were established for the findings of the investigation. Corrective actions relative to the S&RV Program were reviewed.

Condition Reports have been issued for each relief valve failure and programmatic issues. Since the NRC finding on the program and the corrective actions of CR-VTY-2003-1910, equipment failures have been assigned as Level "B." Improvements in the content of the evaluation and subsequent disposition are evident.

Based upon the CRs and corrective action reviewed above, the auditor concluded that commitments were tracked to completion with extensions documented and approved. Overall, corrective actions were considered timely and where delays existed, appropriate justification was provided.

### Self Evaluation Effectiveness

Based upon a review of selected self-assessments/benchmarks, it was concluded that the self assessments were of acceptable depth and were adequately intrusive. Recommendations were being tracked. It was noted that LOCs were used in two instances where CRs would have been more appropriate.

### Check Valve Program

A benchmarking trip was performed on OS116/04 to compare VY's Check Valve Program to that of Seabrook Station and included the CV Program Engineer, IST Program Engineer, and a mechanical maintenance support engineer. A review of the preliminary draft of the report revealed corrective actions would be issued for the evaluation of enhancements to the program. These included employing non-intrusive digital radiography methods, procedure enhancement for dimensional checks during disassembly and inspections, development of a condition monitoring process in support of IST, the use of leak rate testing results as a trending tool for determining check valve degradation, and an effectiveness of corrective actions review.

### Relief Valve Program

An on-going Self Assessment (MSA 2003-015) was performed under commitment OPVY-2003-065\_01. Recommendations resulting from the assessment were documented in the assessment and were entered into the corrective action process. The assessment included team members from the IST, Component Engineering, and Maintenance Support. The S&RV Program Engineer was aware of the status of all open items and is tracking the items under the program improvement plan.

### Reactor Vessel Internals Program

During the course of this assessment, a review of the BWRVIP Program Self Assessment that occurred following RFO 24, was performed. Although this assessment was found to be quite comprehensive, there were at two instances noted where LOCRs were written when CRs were the appropriate documents. Both examples involved the use of an incorrect examination method and frequency which were not in accordance with BWRVIP guidelines (VT-3 versus VT-1 visual exams). A failure to comply with BWRVIP guidance should have triggered a CR, not an LOCR. CR-VTY-2004-03086 was initiated to address this issue.

In both instances, the VT-1 examinations produced acceptable results. Recommendations within the self assessment indicate that the applicable tables in Procedure PP 7027 will be revised to capture the correct examination method and frequency requirements.

### Training/Qualifications

One of the five program engineer positions, EQ, had a qualification card item directly related to their EQ position at the time of the audit. The VY ESP Qualification Matrix indicated that position specific qualifications for all of the positions except the Reactor Internals Program Engineer were being developed for implementation across Entergy North. There is an ISI Engineer Qualification Card to be developed which could be used for the Vessel Internals. All of the current program engineers have had background, experience, and training relevant to their areas of responsibility.

Based upon a review of the training provided on check valves the auditor recommended that an ESP Qualification activity be established for check valve diagnostics and analysis equivalent to that for the MOV/AOV Programs. Also, since two component engineers had received off-site check valve diagnostic training, 0700.03 forms should be submitted to training to get training credit. (LO VTYLO-2004-0512 CA 2 and CA 3)

### Records/Document Control

While QA records and document control was acceptable within the Check Valve and Safety & Relief Valve Programs, temporary and permanent storage issues were identified within the FAC Program.

#### Check Valve Program and Safety & Relief Valve Programs:

Records reviewed from QA record files, packages in process, and Curator/FYI were legible and retrievable. Work order package records were legible with entries made in ink. Two instances were noted where a write-over or cross-out without initials occurred. However, this was a significant improvement over the condition of maintenance records reviewed on previous audits.

Work Order records that were completed and not transferred to RIMS were stored in the locked Work Control QA Records fire proof file cabinets. Incomplete records that have completed procedure data-sheets attached are not treated as QA records until complete. This was discussed with QA Records personnel in RIMS and is consistent with all records at the site for in-process work such as design changes and procedures where the package is not treated as a QA record until complete with the last signature. This interpretation is consistent with the QAPM and with ANSI 45.2.9.

## FAC

Based upon a review of data sheets from RFO 23, and 24 and documents retrieved from CURATOR, the records are legible. However, several issues were identified with document storage and transferal to RIMS.

Although the current records from RFO 24 were being maintained in a fire proof cabinet, other QA records such as the 2002 Refueling Outage Inspection Report (RFO 23 - Fall 2002) and supporting documentation were being maintained by the FAC Program Coordinator on a bookshelf.

As discussed earlier in "Inspections / surveillances, a significant amount of FAC Program documentation had not been sent to RIMS. These issues were documented in CR-VTY-2004-03061 and CR-VTY-2004-03062.

## LIST OF ATTACHMENTS

ATTACHMENT 1 - Personnel Contacted

**ATTACHMENT 1 - PERSONNEL CONTACTED**

Name	Department or Title	Contact
I. Dreyfuss	Director Engineering	1,3
J. Callaghan	Manager Design Engineering	1,3
J. Wierzbowski	Manager System Engineering	1, 3
A. Haumann	EQ Program Coordinator	1
E. Luciano	PM Coordinator, (C)	1
C. Rose	EPU, VY	1
I. Fitzpatrick	Senior Eng ME&S	1
S. Goodwin	Supervisor ME&S	1
J. Apostoles	Sr. Plant Mechanic, VY	1
W.Aho	VY OE Coordinator	1
T. Underkoffler	Appendix J Program Coordinator, VY	1
M. Garland	Mechanical Maintenance Supervisor, VY	1
J. Golonka	EPIX Coordinator, VY	1
R. Penny	Mgr, Eng Programs WPO	1
I. Lafferty	Sr Engineer (Nuc) WPO, VY IVVI Coord	1
W. Fields	Technical Spec IV (Nuc)	1
C. Larson	PNPS	1
J. Devincendis	Licensing Manager VY	1
L. Lukens	ISTPC, VY	1,3
B. Smith	Maint. Support Eng., VY	1
R. Booth	Check Valve Program Coordinator	1
T. Derting	IT SQA Program Administrator, VY	1
P.Longo	MOVATS Engineer, VY	1
M. Faunce	MOV Group Engineer	1
R. Wanczyk	Director, NSA	3
I. O'Connor	QA	3
S. DiMauro	QA	3
T. White	QAManager	3

1 - Contact

2 - Pre-Audit Conference - Informal

3 - Post-Audit Conference 10/07/04)

Originator: Hall, Bruce E

Originator Phone: 5587

Originator Group: Eng DE Manager

Operability Required: N

Supervisor Name: Callaghan, James H

Reportability Required: N

Discovered Date: 10/04/2004 13:24

Initiated Date: 10/04/2004 13:28

**Condition Description:**

QA records not handled in accordance with procedures

During Audit QA-8-2004-VTY-1, Engineering Programs, a number of noncompliances with plant procedures were noted, these included:

There is a significant backlog of FAC documents that have not been sent to RIMS. AP 6807, step 4.1.11.4 requires that QA records not be in temporary storage for more than 6 months.

Some QA documents that have not been sent to RIMS are not being stored in fireproof cabinets. AP 6807, section 4.1.1.1 requires completed QA records to be stored in 1 hr fire proof repositories.

CHECKWORKS predictive models have not been sent to RIMS for permanent storage as required by PP 7028, step 6.1.2

**Immediate Action Description:****Planned Action Description:****TRENDING (For Reference Purposes Only):**Trend Type

KEYWORDS

CAUSE DEPT

HOW IDENTIFIED

KEYWORDS

HUTYPE

KEYWORDS

CAUSAL FACTOR CODES

HU EVALUATION FORM

KEY ACTIVITY

WORK PROCESS

Trend Code

KW-HU CLOCK RESET DEPT

CD-MECHANICAL - CIVIL/STRUCTURAL ENG.

HI-QAD

KW-PROCEDURE ADHERENCE

HU-PRECURSOR

KW-DOCUMENTATION PROBLEM

CFC-F4B4

HU-WB-PROCEDURE USE

KA-DS

WP-DM

**Version:**

· Significance Code: C - MPC & CORRECT

:lassification Code: C

Owner Group: Eng DE Mech Civil Struct Mgmt

Performed By: Burger, Frederick J

10/05/2004 13:44

**Assignment Description:**

CR-VTY-2004-3062

Screening Data

☐ Significance DC - MPC & CORRECT

Downer: ☐ Eng DE Mech Civil Struct Mgmt

☐ Presented By: ☐ Goodwin, Scott

Comments:

DA Human Performance Evaluation VYAPF 0009.05 is required for all HU identified CRs

Trending Items

DOCUMENTATION PROBLEM

ERROR PRECURSOR-HU

HU CLOCK RESET DEPT

PROCEDURE ADHERENCE

QAD Identified

All paperwork that is planned to be transferred to RIMS has been temporarily placed in fire proof cabinets.

**Initiated Date:** 10/4/2004 13:28**Owner Group:** Eng DE Mech Civil Struct Mgmt**Current Contact:** FJB**Current Significance:** C - MPC & CORRECT**Closed by:** Felumb,Rhonda

3/22/2005 9:23

**Sununary Description:**

QA records not handled in accordance with procedures

During Audit QA-8-2004-VTY-1, Engineering Programs, a number of noncompliances with PP were noted these included:

There is a significant backlog of FAC documents that have not been sent to RIMS. AP 6807, step 4.1.11.4 requires that QA records not be in temporary storage for more than 6 months.

Some QA documents that have not been sent to RIMS are not being stored in fireproof cabinets. AP 6807, section 4.1.1.1 requires completed QA records to be stored in 1 hr fire proof repositories.

CHECKWORKS predictive models have not been sent to RIMS for permanent storage as required by PP 7028, steep 6.1.2

**Remarks Description:****Closure Description:**

Condition Report Closure Review LAW LI-102 Section 5.9.1 Completed

CA Number:

Group

Name

Assigned By: CRG/CARB/OSRC

Assigned To: Eng DE Mech Civil Struct Mgmt

Goodwin, Scott D

Subassigned To: Eng DE Mech Civil Struct Staff

Fitzpatrick, James C

Originated By: Burger, Frederick J

10/05/2004 13:48:55

Performed By: Goodwin, Scott D

11/02/2004 15:24:21

Subperformed By: Goodwin, Scott D

11/02/2004 15:23:28

Approved By:

Closed By: Felumb, Rhonda

11/02/2004 15:57:02

Current Due Date: 11/02/2004

Initial Due Date: 11/02/2004

CA Type: CR DISPOSITION

Plant Constraint: 0 NONE

CA Description:

CR Disposition

OQA records not handled in accordance with procedures

O(Review CR for Full Details)

CR-VTY-2004-3062

OReview Screening Comments on the Assignment Tab

O

OThe CRG has initially classified this CR as

JClassification Code - "C"

JSignificance Code - "MPC & CORRECT"

O

LJFollow the process provided in AP 0009 Appendix K. If during your investigations into this event it is determined that the classification should be changed, contact the CA & A representative for re-consideration by the CRG.

J

OPerform Most Probable Cause Evaluation. Issue the appropriate CAs. (per LI 102)

O

OCR Disposition Guidelines: This is only a guide. It is not a substitute for the applicable procedures.

LJ

OAll Attachments are to be in PDF format

O

OoAttach Most Probable Cause Investigation Report or Document in the Response or Sub response field

OoEnsure all Screening Comments have been addressed in the investigation - (CR assignment tab)

OoDevelop adequate corrective actions and issue CAs. (Due Dates per LI 102 Attachment 9.5)

Do LT CAs Require Approval from Manager/ GMPO or Director prior to initiating

OoAttach completed VYAPF 0009.02 (CR Trend Input Data Sheet) in accordance with Appendix E.

OoAttach completed VYAPF 0009.05 (Human Performance Evaluation) if required. Include Cause Dept

OooAttach completed EN-LI-118 Attachment 9.17 (Equipment Failure Evaluation Checklist) .if assigned.

OoSpecify any references needed and enter into Ref. Items.

Response:

Review CRG Screening comments on Initiation Tab for inclusion in the report.



Subresponse:

QA records not handled in accordance with procedures.

'PC-1 [F.4.bA] Documents not followed correctly. FAC documents such as worksheets, reports, and CHECWORKS predictive models have not been sent to RIMS for permanent storage. Also, documents not sent to RIMS are to be stored in a fireproof cabinet until they have been transmitted

Immediate/Interim Actions Completed

Item #0 Action Taken:

MPC-1 ☐ Placed documentation in fireproof cabinet until they are transmitted to RIMS.

☐

☐

Proposed/Assigned Corrective Actions

Item #	CA Type	Assigned Department	Due Date	CA #
MPC-1 <input type="checkbox"/>	Transmit FAC documentation to RIMS	SOCAODE Mech Struct	3-18-05	000002
<input type="checkbox"/>	Closure of CROO	CA	DE Mech Struct	4-1-05 00003

Closure Comments:

Trending data entered and additional CAs have been generated.

Attachments:

Subresp Description

Trend and HU

# Attachment Header

Document Name:

lcR-VTY-2004-03062 CA-00001

Document Location

Subresp Description

Attach Title:

Trend and HU

# ENVY HUMAN PERFORMANCE EVALUATION FORM

CR No: CR VTY-2004-03062	Dispositioning Dept: MSD
	Cause Department: MSD

<b>Applicable HU TRAPS:</b>		
<input type="radio"/> Time Pressure	<input type="radio"/> Vague Guidance	<input type="radio"/> Physical Environment
<input type="radio"/> Distraction/Interruption	<input type="radio"/> First Shift/Late Shift	<input type="radio"/> Mental Stress
<input type="radio"/> Multiple Tasks	<input type="radio"/> Peer Pressure	
<input type="radio"/> Overconfidence	<input type="radio"/> Change/Off-Normal	

<b>Description of Inappropriate Act(s):</b>	<b>Assoc Process/Prog/Org Issue(s):</b> <input checked="" type="checkbox"/> N/A
FAC personnel have not complied with procedures regarding the storage and/or transmittal of QA documents.	

<b>Worker Behaviors:</b>		
<input checked="" type="checkbox"/> Procedure Use/Adherence	<input type="radio"/> Self-Checking	<input type="radio"/> Fitness for Duty
<input type="radio"/> Placekeeping	<input type="radio"/> Peer Checking	<input type="radio"/> Turnover/Handoff
<input type="radio"/> Spoken Communication	<input type="radio"/> Knowledge	<input type="radio"/> Problem Solving Method
<input type="radio"/> Written Communication	<input type="radio"/> Skill	

<b>Supervisor Behaviors:</b>		
<input type="radio"/> Spoken Communication	<input type="radio"/> Task Allocation	<input type="radio"/> Pre-Job Brief
<input type="radio"/> Written Communication	<input type="radio"/> Clear Expectations	

<b>Management Behaviors:</b>		
<input type="radio"/> Communications	<input type="radio"/> Change Management	<input type="radio"/> Scheduling/Sequencing
<input type="radio"/> Resource Allocation	<input type="radio"/> Conservative Decision Mkg	<input type="radio"/> Clear Expectations

<b>Process/Programmatic/Organizational Issues:</b>		
<input type="radio"/> Ergonomic/Human Factors	<input type="radio"/> Housekeeping	<input type="radio"/> Procedure/Nvk Pkg Quality
<input type="radio"/> Environmental Conditions	<input type="radio"/> Equipment Labeling	<input type="radio"/> Training

Dispositioner: T. M. O'Connor	Date Completed: 11-2-04
-------------------------------	-------------------------

# CR TRENDING INPUT DATA SHEET

CR No: CR-VTY-2004-03062	Dispositioning Dept: MSD
	Cause Department (if HU): MSD

## NOTE

See Appendix E (CR Trending) for instructions on how to obtain information with which to complete this form

## CAUSE CODES

MPC-1 [F.4.b.4]

## KEYWORDS

Documentation

Procedure Adherence

## WORK PROCESS

OM

## KEY ACTIVITY

DS

CA Number: 2

	Group	Name
Assigned By:	Eng DE Mech Civil Struct Staff	O'Connor, Thomas M
Assigned To:	Eng DE Mech Civil Struct Mgmt	Goodwin, Scott D
Subassigned To:	Eng DE Meeh Civil Struct Staff	Fitzpatrick, James C
Originated By:	O'Connor, Thomas M	11/02/2004 14:04:41
Performed By:	Goodwin, Scott D	031161200515:14:4S
Subperformed By:		
Approved By:		
Closed By:	Goodwin, Scott D	03116/200515:14:4S

Current Due Date: 03/18/2005

Initial Due Date: 0311812005

CA Type: CORRECTIVE ACTION

Plant Constraint: 0 NONE

**CA Description:**

Transmit FAC documentation to RIMS

**Response:**

Transmittal is complete. Refer to e-mail enclosed as Att 1. No further actions required for this CA.

Subresponse :

**Closure Comments:****Attachments:**

Resp Description

FAC Doc Transmittal E-mail

# Attachment Header

Document Name:

untitled

Document Location

/Resp Description

Attach Title:

IFAC Doc Transmittal E-mail

**Goodwin, Scott**

**From:** Graves, Amy  
**Sent:** Wednesday, March 16, 2005 2:43 PM  
**To:** Goodwin, Scott  
**Cc:** Fitzpatrick, Jim; O'Connor, Tom  
**Subject:** FW: FAC INFO to RIMS for CR-VTY-2004-3062 CA2

Scott - Records indicated below have been transferred to RIMS in checklist number 02668. This transfer has been completed. Therefore, enabling you to close this commitment.

---

**From:** Fitzpatrick, Jim  
**Sent:** Monday, March 14, 2005 8:24 PM  
**To:** Graves, Amy  
**Cc:** Goodwin, Scott; O'Connor, Tom  
**Subject:** FAC INFO to RIMS for CR-VTY-2004-3062 CA2

Amy,

I have a CA to transmit FAC Program Inspection data and CHECWORKS Model data to RIMS by 3/18/03 (CR-VTY-2004-0362 CA2). There is a lot of data to be scanned.

The QA records for the 2004 RFO for the FAC Inspection program as required by PP 7028 have been assembled and indexed. They are located in the top drawer of the fire proof file in the PSB NW corner. The 2004 data package is similar to the 2001 RFO & 2002 RFO files previously sent to RIMS. These are originals so they should stay in the file.

In addition to the 2004 RFO inspection data there are 5 new documents to go to RIMS:

1. 1996 CHECWORKS Models & Results
2. 1996 EPRI CHECWORKS Database
3. 2001 EPRI CHECWORKS Database
4. EPRI CHECWORKS Wear Rate Analysis Results Cycles 20 & 21
5. EPRI CHECWORKS Wear Rate Analysis Results Cycles 22B

These are also in the top drawer of the fire proof file.

Please have these scanned and sent to RIMS. I will be out of the office the remainder of this week but can be reached at 603-778-1144. Also Tom O'Connor can help to identify items. Please tell Scott when the data has been transmitted so he can close out the CA or if you need more help.

Thanks,  
(Sorry for the data dump)

Jim Fitz.

Thanks,

Jim Fitz.

CA Number: 3

**Group****Name**

Assigned By: Eng DE Mech Civil Struct Mgmt

Assigned To: Eng DE Mech Civil Struct Mgmt

Subassigned To :

Originated By: Goodwin,Scott D

11/02/2004 15:09:40

Performed By: Goodwin,Scott D

03/16/2005 19:31:43

Subperformed By:

Approved By:

Closed By: Goodwin,Scott D

03/16/2005 19:31:43

Current Due Date: 04/01/2005

Initial Due Date: 04/01/2005

CA Type: EN CA

Plant Constraint: 0 NONE

**CA Description:**

Perform CR Closure review IAW EN-LI-102 requirements.

**Response:**

CR Disposition and all CAs have been reviewed and are considered closed. No further actions are required. IAW LI-102 requirements for closure, this CR should be closed.

Subresponse :

sure Comments:



**Initiated Date:** 10/4/2004 13:23**Owner Group :**Eng DE Mech Civil Struct Mgmt**Current Contact:** FJB**Current Significance:** C - MPC & CORRECT**Closed by:** Felumb,Rhonda

2/16/2005 16:37

**Sununary Description:**

RFO 24 FAC documentation not yet completed

Formal documentation of FAC erosion rate on analysis/worksheets has not been completed for the data taken during RFO 24. The FAC Coordinator indicated that the Ultrasonic data had been reviewed, but the worksheets have not yet been completed to document the wear rate. Since the wear rates are not yet completed, the post outage FAC report has also not yet been completed although PP 7028, section 4.4.12 requires that the report be issued within 90 days.

**Remarks Description:****Closure Description:**

Condition Report Closure Review IAW LI-102 Section 5.9.1 Completed

Originator: Hall, Bruce E

Originator Phone: 5587

Originator Group: Eng DE Manager

Operability Required: N

Supervisor Name: Callaghan, James H

Reportability Required: N

Discovered Date: 10/04/2004 13:21

Initiated Date: 10/04/2004 13:23

**Condition Description:**

RFO 24 FAC documentation not yet completed

Formal documentation of FAC erosion rate on analysis/worksheets has not been completed for the data taken during RFO 24. The FAC Coordinator indicated that the Ultrasonic data had been reviewed, but the worksheets have not yet been completed to document the wear rate. Since the wear rates are not yet completed, the post outage FAC report has also not yet been completed although PP 7028, section 4.4.12 requires that the report be issued within 90 days. This condition report documents a QA identified issue. This issue was identified during the performance of Engineering Program Audit number QA-8-2004-VTY-1.

**Immediate Action Description:****Suggested Action Description:****TRENDING (For Reference Purposes Only):****Trend Type**

KEYWORDS  
KEYWORDS  
HOW IDENTIFIED  
HUTYPE  
CAUSE DEPT  
HU EVALUATION FORM  
WORK PROCESS  
HU EVALUATION FORM  
KEYWORDS  
CAUSAL FACTOR CODES  
CAUSAL FACTOR CODES  
KEY ACTIVITY  
HU EVALUATION FORM

**Trend Code**

KW-HU CLOCK RESET DEPT  
KW-PROCEDURE ADHERENCE  
HI-QAD  
HU-PRECURSOR  
CD-MECHANICAL - CIVIL/STRUCTURAL ENG.  
HU-TRAP-MULTIPLE TASKS  
WP-DM  
HU-TRAP-DISTRACTION  
KW-DOCUMENTATION PROBLEM  
CFC-E3Z4  
CFC-F4B4  
KA-AN  
HU-WB-PROCEDURE USE

**Initiated Date:** 10/4/2004 13:23**Owner Group :** Eng DE Mech Civil Struct Mgmt**Current Contact:** FIB**Current Significance:** C - MPC & CORRECT**Closed by:** Felumb,Rhonda

2/16/2005 16:37

**Sununary Description:**

RFO 24 FAC documentation not yet completed

Formal documentation of FAC erosion rate on analysis/worksheets has not been completed for the data taken during RFO 24. The FAC Coordinator indicated that the Ultrasonic data had been reviewed, but the worksheets have not yet been completed to document the wear rate. Since the wear rates are not yet completed, the post outage FAC report has also not yet been completed although PP 7028, section 4.4.12 requires that the report be issued within 90 days.

**Remarks Description:****Closure Description:**

Condition Report Closure Review IAW LI-102 Section 5.9.1 Completed

**Version:**

**Significance Code:** C - MPC & CORRECT

**Classification Code:** C

**Owner Group:** Eng DE Mech Civil Struct Mgmt

**Performed By:** Burger, Frederick J

10/05/2004 13:32

**Assignment Description:**

CR-VTY-2004-3061

Screening Data

OSignificanceDC - MPC & CORRECT

Downer: 0-Eng DE Mech Civil Struct Mgmt

DPresented By: 0 Goodwin, Scott

Comments:

DA Human Performance Evaluation VYAPF 0009.05 is required for all HU identified CRs

Trending Items

Cause Department -DE Mech Civil Structural

ERRORPRECURSOR-HU

HU CLOCK RESET DEPT

PROCEDURE ADHERENCE

Self-Identified

Discussed with FAC Coordinator. All RFO inspections have been evaluated and have been IR. There are no outstanding issues related to plant ops. Issue is administrative and relates to timely closure of paperwork.

CA Number:

**Group**

**Name**

Assigned By: CRG/CARB/OSRC

Assigned To: Eng DE Mech Civil Struct Mgmt

Goodwin, Scott D

Subassigned To: Eng DE Mech Civil Struct Staff

Fitzpatrick, James C

Originated By: Burger, Frederick J

10/051200413:41:55

Performed By: Goodwin, Scott D

1110212004 15:27:15

Subperformed By: O'Connor, Thomas M

11/02/2004 15:09:38

Approved By:

Closed By: Felumb, Rhonda

1110212004 15:50:51

Current Due Date: 1110212004

Initial Due Date: 11102/2004

CA Type: CR DISPOSITION

Plant Constraint: 0 NONE

**CA Description:**

OCR Disposition

10RFO 24 FAC documentation not yet completed

O(Review CR for Full Details)

CR-VTY-2004-3061

OReview Screening Comments on the Assignment Tab

O

OThe CRG has initially classified this CR as

OClassification Code - "C"

OSignificance Code - " MPC & CORRECT"

[J

OFollow the process provided in AP 0009 Appendix K. If during your investigations into this event it is determined

[Jthat the classification should be changed, contact the CA&A representative for re-consideration by the CRG.

O

OPerform Most Probable Cause Evaluation. Issue the appropriate CAs. (per LI 102)

O

OCR Disposition Guidelines: This is only a guide. It is not a substitute for the applicable procedures.

O

OAll Attachments are to be in PDF format

O

OoAttach Most Probable Cause Investigation Report or Document in the Response or Sub response field

OoEnsure all Screening Comments have been addressed in the investigation - (CR assignment tab)

OoDevelop adequate corrective actions and issue CAs. (Due Dates per LI 102 Attachment 9.5)

00 LT CAs Require Approval from Manager/ GMPO or Director prior to initiating

OoAttach completed VYAPF 0009.02 (CR Trend Input Data Sheet) in accordance with Appendix E.

OoAttach completed VYAPF 0009.05 (Human Performance Evaluation) if required. Include Cause Dept

OooAttach completed EN-LI-118 Attachment 9.17 (Equipment Failure Evaluation Checklist) if assigned.

OoSpecify any references needed and enter into Ref. Items.

**Response:**

Review CRG Screening notes on Initiation Tab for inclusion in report.

## Subresponse :

FAC paperwork for RF024 not completed within 90 days of outage as required by procedure.

IPC-I [FA.bA] Documents not followed correctly; Procedure requires summary report to be issued within 90 days of outage completion. Although all data was evaluated and independently reviewed all formal worksheets had not been completed and hence the final report was not issued within the required time frame. Completion of formal worksheets is in progress with report to follow.

MPC-2 [E.3.zA] Contributing to the problem was ongoing work and emergent issues.

## Proposed/Assigned Corrective Actions

Item #0 Action0

CA Type Assigned Department Due Date CA #

MPC-I OComplete FAC Worksheets and Issue Final Report DCAODE Mech StructD 12-6-04000002

## Closure Comments:

Trending data entered and additional CAs have been generated.

## Attachments:

Subresp Description  
trend and hu

# Attachment Header

Document Name:

CR-VTY-2004-03061 CA-00001

Document Location

ISUbrsp Description

Attach Title:

trand and hu

# ENVY HUMAN PERFORMANCE EVALUATION FORM

CR No: CR-VTY-2004-03061	Dispositioning Dept: MSD
	Cause Department: MSD

<b>Applicable HU TRAPS:</b>		
<input type="checkbox"/> Time Pressure	<input type="checkbox"/> Vague Guidance	<input type="checkbox"/> Physical Environment
<input checked="" type="checkbox"/> Distraction/Interruption	<input type="checkbox"/> First Shift/Late Shift	<input type="checkbox"/> Mental Stress
<input checked="" type="checkbox"/> Multiple Tasks	<input type="checkbox"/> Peer Pressure	
<input type="checkbox"/> Overconfidence	<input type="checkbox"/> Change/Off-Normal	

<b>Description of Inappropriate Act(s):</b>	<b>Assoc Process/Prog/Org issue(s):</b> <i>NJA</i>
FAC personnel did not comply with procedure to complete RFO associated paperwork within 90 days of outage completion.	Multiple ongoing tasks and emergent issues contributed to paperwork not being completed in a timely fashion.

<b>Worker Behaviors:</b>		
<input checked="" type="checkbox"/> Procedure Use/Adherence	<input type="checkbox"/> Self-Checking	<input type="checkbox"/> Fitness for Duty
<input type="checkbox"/> Placekeeping	<input type="checkbox"/> Peer Checking	<input type="checkbox"/> Turnover/Handoff
<input type="checkbox"/> Spoken Communication	<input type="checkbox"/> Knowledge	<input type="checkbox"/> Problem Solving Method
<input type="checkbox"/> Written Communication	<input type="checkbox"/> Skill	

<b>Supervisor Behaviors:</b>		
<input type="checkbox"/> Spoken Communication	<input type="checkbox"/> Task Allocation	<input type="checkbox"/> Pre-Job Brief
<input type="checkbox"/> Written Communication	<input type="checkbox"/> Clear Expectations	

<b>Management Behaviors:</b>		
<input type="checkbox"/> Communications	<input type="checkbox"/> Change Management	<input type="checkbox"/> Scheduling/Sequencing
<input type="checkbox"/> Resource Allocation	<input type="checkbox"/> Conservative Decision Mkg	<input type="checkbox"/> Clear Expectations

<b>Process/Programmatic/Organizational Issues:</b>		
<input type="checkbox"/> Ergonomic/Human Factors	<input type="checkbox"/> Housekeeping	<input type="checkbox"/> Procedure/Wk Pkg Quality
<input type="checkbox"/> Environmental Conditions	<input type="checkbox"/> Equipment Labeling	<input type="checkbox"/> Training

Dispositioner: T. M. O'Connor	Date Completed: 11-2-04
-------------------------------	-------------------------



# CR TRENDING INPUT DATA SHEET

CR No: CR-VTY-2004-03061	Dispositioning Dept: MSD
	Cause Department (if HU): MSD

## NOTE

See Appendix E (CR Trending) for instructions on how to obtain information with which to complete this form

CAUSE CODES	
MPC-1 [FA, b, A]	MPC-2 [E, 3, Z, A] 1

KEYWORDS	
Documentation	Procedural Adherence

WORK PROCESS	AN
--------------	----

KEY ACTIVITY	OM
--------------	----

CA Number: 2

## Group

## Name

Assigned By: Eng DE Mech Civil Struct Staff

O'Connor, Thomas M

Assigned To: Eng DE Mech Civil Struct Mgmt

Goodwin, Scott D

Subassigned To: Eng DE Mech Civil Struct Staff

Fitzpatrick, James C

Originated By: O'Connor, Thomas M

11/02/2004 14:30:IS

Performed By: Goodwin, Scott D

02/15/2005 16:08:37

Subperformed By: Fitzpatrick, James C

02/15/2005 16:00:15

Approved By:

Closed By: Goodwin, Scott D

02/15/2005 16:08:37

Current Due Date: 02/15/2005

Initial Due Date: 12/06/2004

CA Type: CORRECTIVE ACTION

Plant Constraint: 0 NONE

## CA Description:

Complete Formal FAC worksheets and Issue Final Report

## Response:

Concur with response. No further actions required for this item. SDG 2-15-05

## Subresponse :

Attached .PDF file of 2004 RFO Outage FAC Inspection Report No. VY-RPT-04-00010 Rev.O.

Note the CD containing cross around piping photos is not included here. The CD and any other ENN DC-xx process forms are filed separately in the document control system as required by procedure.

## Closure Comments:

Approval attached to DDE #2.

## Attachments:

Subresp Description

VY-RPT-04-00010 RevO

# Attachment Header

Document Name:

---

Document Location:

---

ISUbrsp Description

---

Attach Title:

---

W-RPT-04-0001O ReVO

Engineering Report No. VY-RPT-04-00010 Rev. 0Page 1 of 20

Plus attached CD



ENTERGY NUCLEAR NORTHEAST

Engineering Report Cover Sheet

Engineering Report Title:

VERMONT YANKEE PIPING FLOW ACCELERATED CORROSION  
INSPECTION PROGRAM (PP 7028)  
2004 REFUELING OUTAGE INSPECTION REPORT  
(RFO 24- Spring 2004)

Engineering Report Type:

New ☒Revision 0Cancelled 0Superseded 0

Applicable Site(s)

IP1 DIP2 DIP3 DJAF DPNPS DVY ☒Quality-Related: ☒ Yes 0 No

Prepared by:

James C. Fitzpatrick

Responsible Engineer (Print Name/Sign)

Date:

2/15/05

Verified!

Reviewed by:

Thomas M. O'Connor

Design Verifier/Reviewer (Print Name/Sign)

Date:

2/15/05

\*Reviewed by:

N/A

Authorized Nuclear In-service Inspector (ANII)

Date:

N/A

Approved by:

Scott D. Goodwin

Supervisor (Print Name/Sign)

Date:

2-15-05

## Multiple Site Review (10)

Site	Design Verifier/Reviewer (Print Name/Sign)	Supervisor (Print Name/Sign)	Date
	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>

\*: For ASME Section XI Code Program plans per ENN-DC-120, if required.

**Entergy** |**CORRECTIVE ACTION****ICR-VTY-2004-03061**

CA Number: 3

**Group****Name**

Assigned By: Eng DE Mech Civil Struct Staff

O'Connor, Thomas M

Assigned To: Eng DE Mech Civil Struct Mgmt

Goodwin, Scott D

Subassigned To :

Originated By: O'Connor, Thomas M

11/02/2004 15:07:55

Performed By: Goodwin, Scott D

02/16/2005 12:57:45

Subperformed By:

Approved By:

Closed By: Goodwin, Scott D

02/16/2005 12:57:45

Current Due Date: 03/04/2005

Initial Due Date: 12/20/2004

CA Type: CR CLOSURE REVIEW CA

Plant Constraint: 0 NONE

**CA Description:**

Ensure all Corrective Actions are closed out and close CR.

**Response:**

CR Disposition and associated CAs reviewed. All actions required complete. No further actions are required. IAW Section 5 of LI-102 this CR should be closed.

Subresponse :

Closure Comments:

VERMONT YANKEE NUCLEAR POWER STATION

**PROCEDURE**

PP7028

ORIGINAL

**PIPING FLOW ACCELERATED CORROSION INSPECTION PROGRAM**

USE CLASSIFICATION: INFORMATION

LPC No.	Effective Date	Affected Pages
1	12106101	3-5 & 13-15 of 15

**Implementation Statement:** This procedure supercedes VY Procedure DP 4023 and use of the Vermont Yankee Piping Flow Accelerated Corrosion Program Manual, Revision 2a, prepared for Vermont Yankee by Yankee Atomic - Nuclear Services Division.

Issue Date: 05/10/01

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## 1.0 PURPOSE, SCOPE, AND DISCUSSION

### 1.1. Purpose

The purpose of the Vermont Yankee Piping Flow Accelerated Corrosion (FAC) Inspection Program is to provide a systematic approach to ensure that FAC does not lead to degradation of plant piping systems and feedwater heaters. This Program Procedure controls the engineering and inspection activities performed to predict, detect, monitor, and evaluate wall thinning due to FAC at the Vermont Yankee Nuclear Power Station.

### 1.2. Scope

The scope of this program is limited to evaluation and inspection of plant piping systems and feedwater heater shells that could be susceptible to FAC.

FAC is known to occur in piping systems constructed of carbon or low-alloy steels, which carry water or wet steam. All plant piping systems have been screened for susceptibility to damage from FAC. A separate document titled "FAC Susceptible Piping Identification" has been developed to identify, on a line by line basis, the piping which is susceptible to damage from FAC. This document is maintained by the Piping FAC Inspection Program coordinator and is updated as required to reflect changes in plant operation and configuration.

There is no finite scope of piping components to be scheduled for inspection on a periodic basis. Each refueling outage inspection efforts will be optimized to focus on piping components which have been identified as wearing, or potentially wearing due to FAC. The components selected for inspection each refueling outage are identified using:

- Results of ultrasonic thickness (UT) inspections from previous refueling outages.
- Results of the CHECWORKS predictive software, which incorporates actual inspection data.
- Operating conditions at VY, which may indicate PAC damage is occurring.
- Operating experience and events from other plants.

Carbon steel feedwater heater shells have experienced thinning and through wall leaks due to FAC. Vermont Yankee has replaced all low pressure feedwater heaters with new heaters constructed of materials resistant to FAC. The four remaining high pressure feedwater heater shells are carbon steel. Long term monitoring of shell thickness for plant feedwater heaters is included in the scope of this program.

### 1.3. Discussion

Following the December 1986 Surry pipe rupture the industry has worked steadily to develop and implement monitoring programs to prevent the rupture of high energy piping due to single phase erosion-corrosion (FAC). In March 1987 INFO issued Significant Operating Experience Report (SOER) 87-3 which recommended that a continuing program be established at all U.S. nuclear power plants including analyses to predict wear rates and to plan and schedule periodic inspections. USNRC Generic Letter GL 89-08, requires all holders of operating licenses to provide assurances that a systematic program has been implemented to ensure that Flow Accelerated Corrosion does not lead to degradation of plant piping systems.

This Program Procedure (PP) controls engineering and inspection activities performed to assess the susceptible plant piping. This procedure defines the methods and criteria used in the evaluation and inspection of plant piping components which are susceptible to wall thinning due to FAC. The program is based on current industry practice and the latest EPRI recommendations (REF 5.4.8.).



LPC  
1

Long term monitoring of plant feedwater heater shell thickness is included in the scope of this program. Previous heater inspection efforts were performed by Project Engineering and Design Engineering in conjunction with feedwater heater repair and replacement efforts. All six of the low pressure feedwater heaters have been replaced with new heaters constructed of materials resistant to FAC. The four remaining high pressure feedwater heater shells are carbon steel. Design criteria used in the feedwater heater repair and replacement activities are included in the documentation for the corresponding design change or work order which implemented the repair or replacement.

Overall health of the feedwater heaters is not only determined by the condition of the shell and nozzles, but is also dependent on the condition of the heater internals: tubes, tube support plates, impingement plates, tie rods, drain cooler end plates, etc. Evaluation of the overall component health is the responsibility of the Maintenance Department. Shell and nozzle inspections of feedwater heaters will be coordinated through the responsible System Engineer and the Maintenance Support Department. UT inspections of the heater shells will be performed in conjunction with internal visual inspections and eddy current testing of the heater tubes under Preventive Maintenance (PM) work orders.

Elements of the program controlled by this procedure are:

- Criteria for selection of piping systems and components susceptible to FAC and for maintenance of a "FAC Susceptible Piping Identification", which identifies all plant piping susceptible to FAC.
- Criteria for ongoing program maintenance including, benchmarking with current industry practice, evaluation of industry events, and participation in industry working groups.
- Criteria for use and control of the CHECWORKS predictive software used to evaluate piping, plan inspections, track inspection results, wear rates, piping component data, and repair and/or replacement history.
- Criteria for selection and scheduling of components to be inspected during refueling outages including initial inspections, follow-on inspections, and scope expansion / reduction.
- Criteria and procedures for evaluation of thinned piping components and, if required, for repair and replacements.
- Documentation requirements and criteria for maintenance and storage of inspection data.

**NOTE**

LPC  
1

The program only addresses wall thinning due to FAC in pressure boundary piping components and feedwater heater shells. Wear in other pressure vessels, pumps, valves, and in-line items is not included. However, detected wear in the attached piping may indicate wear in the component and should be pursued.

The primary purpose of performing UT inspections each outage is to locate piping components degraded by FAC prior to the time that an immediate repair or replacement is required. This allows sufficient lead time for a planned replacement which will have a minimum impact on plant operation.

Given the costs of inspection and replacement of piping components, a long term approach for mitigating the effects of FAC taken under this program will be towards reducing component wear rates. To accomplish this, components found with significant wall loss due to FAC under this program, will be preferably replaced with materials which are more resistant to FAC damage.

## 2.0 DEFINITIONS

- 2.1. Flow Accelerated Corrosion (FAC): A corrosion process that causes thinning of steel piping exposed to flowing water or wet steam. The rate of loss is dependent on several parameters, which include flow regime, service life, water chemistry, piping material, piping geometry, and hydrodynamics.
- 2.2. Program: A set of activities that benefit from the existence of a formal, high level "Program Document." Such documents are meant to provide for a common understanding of program depth, breath and technical bases as well as the responsibilities of the program owner and those helping to implement the program. "Program Documents" are typically created to ensure regulatory requirements are satisfied. They can also be used to layout the technical bases and personnel responsibilities related to complex, multi-departmental processes.
- 2.3. Program Owner: The individual responsible for maintaining the program, program documents, and assuring proper execution of the program requirements. Each program shall have an individual assigned as the program owner. The appropriate Job title is determined by the responsible Department Manager. A summary of expectations for the program owner are contained in Appendix A of AP 0098 and shall be referenced in all Program Procedures.
- 2.4. Single-Phase Flow: The flow in the piping system remains in the liquid phase at all design and operating pressures and temperatures.
- 2.5. Two-Phase Flow: The flow in the piping system may vary from liquid to wet steam. This depends on the operating pressures and temperatures and varies with the specific location in the piping system.

## 3.0 PRIMARY RESPONSIBILITIES

Implementation of the tasks performed under this program involve several plant departments. The organization for personnel performing tasks under this program is shown in Figure 1.

- 3.1. The VY Design Engineering Mechanical! Structural (DE MIS) Department is responsible for the Piping FAC Inspection Program. The DE MIS Lead Design Engineer (LDE) has responsibility for the overall program management and administration and, for structural evaluation of thinned piping components.

3.1.1. Establishment and maintenance of criteria and procedures for evaluation of thinned wall piping components.

3.1.2. Performing structural evaluations of thinned wall piping components.

- 3.2. The Vermont Yankee Piping FAC Inspection Program Coordinator (FACPC) works within the Mechanical Structural (DE MIS) Department under the direction of the DE MIS LOE. The responsibilities of the FAC Program Coordinator are:

3.2.1. Maintenance of the Vermont Yankee Piping FAC Inspection Program Procedure and supporting documents to ensure that program meets commitments to GL 89-08 and the "Expectations of Program Owners" as defined in Appendix A of AP 0098.

3.2.2. Continual assessment of FAC inspection program to insure program effectiveness.

3.2.3. Participation in relevant industry working groups, benchmarking with current industry practice, evaluation of industry events; and implementation of revisions, changes, and process improvements which result from the participation.

3.2.4. Establishment and maintenance of criteria for selection of piping systems and components susceptible to FAC and for maintenance of the "FAC Susceptible Piping Identification" document which screens all current plant piping systems and identifies piping susceptible to FAG

3.2.5. Establishment and maintenance of criteria for selection and scheduling of components to be inspected during refueling outages including: initial inspections, follow-on inspections, and scope expansion and/or reduction.

- 3.2.6. Establishment and maintenance of criteria for use and control of the CHECWORKS predictive software used to evaluate piping, plan inspections, track inspection results, wear rates, piping component data, and repair and/or replacement history.
- 3.2.7. Review of design change and maintenance documents as necessary to assess the impact of the proposed tasks on the inspection program, and recommend action when appropriate.
- 3.2.8. Ensure that all physical and operational changes or additions to plant piping systems are incorporated into the program.
- 3.2.9. Analytical evaluation of plant piping systems for FAC using the EPRI CHECWORKS codes as appropriate.
- 3.2.10. Pre-outage activities including:
- Development of inspection scope for each refueling outage.
  - Perform/update analytical evaluations (CHECWORKS models) as required.
  - Provide pre-inspection implementation support.
- 3.2.11. Outage activities including:
- Providing engineering support for inspection implementation.
  - Evaluation and disposition of all inspection results.
  - Recommend changes to the planned inspection scope upon discovery of unacceptable conditions.
  - Providing assistance as required in the development of repair/replacement options.
  - Providing written summary of inspection results to ISIPC prior to plant startup.
  - Ensure that cognizant departments and the Control Room are informed of unacceptable conditions discovered during evaluation of inspection results and facilitate completion of appropriate paperwork (ER's, WOR, IDR, etc.).
- 3.2.12. Post-outage activities including:
- Development of outage inspection report including trending analyses and long term recommendations.
  - Update/maintain the plant CHECWORKS models and maintain a history of all piping inspections.
  - Update/maintain "FAC Susceptible Piping Identification" document to reflect plant changes as required.
- 3.2.13. Keep DE *MIS* LDE informed on the progress of FAC related tasks.

- 3.3. The Vermont Yankee In-Service Inspection Program Coordinator (ISIPC): works within the System Engineering Department under the direction of the Superintendent of System Engineering. The responsibilities of the ISIPC include:
- 3.3.1. Provide for overall coordination with the Vermont Yankee In-Service Inspection Program if inspection results on safety class piping indicate violations of the piping design code.
  - 3.3.2. Coordination of pre-outage activities including:
    - Input to the development of outage schedules and budgets relative to FAC activities.
    - Providing oversight of work order planning and coordination with ISI Program resources.
    - Arrange on-site services as required.
  - 3.3.3. Coordination of outage activities including:
    - Ensure components scheduled for inspection are properly prepared and accessible.
    - Performance of inspections.
    - Post inspection restoration of components.
    - Repair/replacement effort of unacceptable components.
  - 3.3.4. Interface with the cognizant departments, as needed to insure all safety related repair/replacement ISI examination requirements are satisfied.
  - 3.3.5. Ensure that required piping repairs and/or replacements are performed according to plant procedures and repairs to safety class piping and components are performed in accordance with ASME Section XI requirements.
  - 3.3.6. Ensure that cognizant departments and the Control Room are informed of unacceptable conditions discovered during evaluation of inspection results and facilitate completion of appropriate paperwork (ER's, WOR, IDR, etc. ).
  - 3.3.7. Ensure that inspection records are temporarily stored per AP 6807 and permanently stored per AP 6809 and available for the plant lifetime.
  - 3.3.8. Keep the Superintendent of System Engineering informed on the progress of FAC related tasks.
  - 3.3.9. Provide technical advice on implementation and inspection aspects of the FAC program.
  - 3.3.10. NDE procedure development and maintenance.

3.4. Level III / ISI Supervisor is a certified Level III UT examiner and works under the direction of the ISIPC. The responsibilities of the Level III / ISI Supervisor include:

- 3.4.1. Review of applicable NDE procedures used in pipe tJT wall thickness measurements.
- 3.4.2. Ensuring that UT inspectors are properly qualified and trained to the applicable inspection procedures.
- 3.4.3. Review of inspection results for compliance to the applicable procedures.
- 3.4.4. Resolution of anomalies found in inspection data.
- 3.4.5. Recommendations for augmented or special NDE procedures or techniques as required.
- 3.4.6. Direct supervision of inspection personnel to ensure that the inspection personnel accurately and efficiently execute the inspection plan, complete inspections, and appropriately document inspection results.
- 3.4.7. Control of all inspection data during the refueling outage.
- 3.4.8. At the completion of inspections forwarding all inspection records to the ISIPC for permanent storage per the requirements of Section 6.2

3.5. Non Destructive Examination (NDE) Personnel

- 3.5.1. Meet Applicable qualification Standards. Personnel performing ultrasonic inspections shall be qualified to the requirements of NE 8043.
- 3.5.2. Perform assigned setup, calibrations, and examinations.
- 3.5.3. Documentation of results in accordance with approved procedures.

3.6. Plant Support Services

The Project Engineering Department is responsible for providing staging, lighting, insulation removal, surface preparation of piping components, and for component restoration after inspections are performed. Activities are controlled through the VY Work Order process in accordance with plant procedures.

#### **4.0 PROCEDURE**

##### **4.1. Program Maintenance**

The FACPC shall maintain the Yankee Piping FAC Inspection Program Procedure, PP 7028 and supporting documents to ensure that program meets commitments to GL 89-08 by:

- 4.1.1. Continual reassessment of the piping FAC inspection program to insure program effectiveness. A FAC Program Self Assessment shall be performed at least once per operating cycle.
- 4.1.2. Participation in relevant industry working groups, benchmarking with current industry practice, evaluation of industry events; and implementation of revisions, changes, and process improvements which result from the participation.
- 4.1.3. Adaptation of current or developing industry practices: for selection and scheduling of components to be inspected, follow-on inspections, scope expansion and/or reductions, and criteria and procedures for evaluation of thinned wall piping components.
- 4.1.4. Review design change and maintenance documents as necessary to assess the impact of the proposed tasks on the inspection program, and recommend action when appropriate.
- 4.1.5. Incorporate all physical and operational changes or additions to plant piping systems into the program as applicable.

##### **4.2. Initial Screening and Identification of FAC Susceptible Piping**

- 4.2.1. A screening and evaluation of all plant piping systems for susceptibility to FAC shall be performed. The screening shall use the EPRI Guidelines from reference 5.4.8., industry experience, and previous Vermont Yankee inspection results. The evaluation shall be performed and reviewed by engineers with FAC experience and familiar with plant systems. The resulting document shall be controlled by the FACPC.
- 4.2.2. The FACPC shall revise the "FAC Susceptible Piping Identification" document as required to reflect changes in plant operation, piping configuration, and/or materials.

##### **4.3. CHECWORKS Modeling**

- 4.3.1. Evaluate the susceptible plant piping systems for FAC using the EPRI CHECWORKS code. The evaluations shall be performed, reviewed, and documented per the requirements of Appendix D.

#### 4.4. Outage to Outage Activities

Inspection and evaluation efforts performed under the program follow a cyclic pattern. Once inspection data from a given outage is obtained, it is incorporated into the appropriate predictive model and the results are then used in conjunction with other FAC related information to establish the inspection scope for the next refueling outage.

##### **NOTE**

Each large bore piping component within the scope of this program has been given a unique identification number as described in Appendix A. The location (building and elevation) of each large bore component is obtained from the Component Location Sketches in Appendix A. Small bore piping inspection locations included in the program are identified in Appendix B.

The tasks performed each refueling outage to implement the piping inspections under the FAC inspection program are detailed below. These are also broken out chronologically in a flow chart included here as Figure 2.

- 4.4.1. The outage inspection scope is determined by the FACPC using previous inspection data, the results of the CHECWORKS models, industry experience, and the guidelines contained in Appendix E.
- 4.4.2. The outage inspection scope is reviewed by the ISIPC for impact on and conflicts with the overall outage plan. The ISIPC will plan and organize the on-site resources required to implement the piping inspections.
- 4.4.3. A work package is assembled for each piping component or group of components. This package includes component location sketches, support requirements such as scaffolding, lighting, etc., surface preparation and gridding requirements, and any special inspection requirements as determined by the FACPC.
- 4.4.4. Prepare piping components for inspection.
  - 4.4.4.1. As directed by the ISIPC, scaffolding, lighting, insulation removal, and surface preparation of each piping component to be inspected are performed by on-site services in accordance with the applicable plant procedures.
  - 4.4.4.2. Surface preparation and gridding of piping components for inspection shall conform to the guidelines in NSAC 202L (reference 5.4.8.). Specific instructions for surface preparation are given in NE 8044. Specific instructions for gridding of piping components are given in Attachment A of NE 8053, or as further directed by the FACPC.

NUREG-1801, Vol. 2, Rev. 1

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# **Generic Aging Lessons Learned (GALL) Report**

## **Tabulation of Results**

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Manuscript Completed: September 2005  
Date Published: September 2005

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





## X.M1 METAL FATIGUE OF REACTOR COOLANT PRESSURE BOUNDARY

### Program Description

In order not to exceed the design limit on fatigue usage, the aging management program (AMP) monitors and tracks the number of critical thermal and pressure transients for the selected reactor coolant system components.

The AMP addresses the effects of the coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant. Examples of critical components are identified in NUREG/CR-6260. The sample of critical components can be evaluated by applying environmental life correction factors to the existing ASME Code fatigue analyses. Formulae for calculating the environmental life correction factors are contained in NUREG/CR-6583 for carbon and low-alloy steels and in NUREG/CR-5704 for austenitic stainless steels.

As evaluated below, this is an acceptable option for managing metal fatigue for the reactor coolant pressure boundary, considering environmental effects. Thus, no further evaluation is recommended for license renewal if the applicant selects this option under 10 CFR 54.21(c)(1)(iii) to evaluate metal fatigue for the reactor coolant pressure boundary.

### Evaluation and Technical Basis

1. **Scope of Program:** The program includes preventive measures to mitigate fatigue cracking of metal components of the reactor coolant pressure boundary caused by anticipated cyclic strains in the material.
2. **Preventive Actions:** Maintaining the fatigue usage factor below the design code limit and considering the effect of the reactor water environment, as described under the program description, will provide adequate margin against fatigue cracking of reactor coolant system components due to anticipated cyclic strains.
3. **Parameters Monitored/Inspected:** The program monitors all plant transients that cause cyclic strains, which are significant contributors to the fatigue usage factor. The number of plant transients that cause significant fatigue usage for each critical reactor coolant pressure boundary component is to be monitored. Alternatively, more detailed local monitoring of the plant transient may be used to compute the actual fatigue usage for each transient.
4. **Detection of Aging Effects:** The program provides for periodic update of the fatigue usage calculations.
5. **Monitoring and Trending:** The program monitors a sample of high fatigue usage locations. This sample is to include the locations identified in NUREG/CR-6260, as minimum, or propose alternatives based on plant configuration.
6. **Acceptance Criteria:** The acceptance criteria involves maintaining the fatigue usage below the design code limit considering environmental fatigue effects as described under the program description.
7. **Corrective Actions:** The program provides for corrective actions to prevent the usage factor from exceeding the design code limit during the period of extended operation.

Acceptable corrective actions include repair of the component, replacement of the component, and a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded during the extended period of operation. For programs that monitor a sample of high fatigue usage locations, corrective actions include a review of additional affected reactor coolant pressure boundary locations. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. **Confirmation Process:** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of Appendix B to 10 CFR Part 50. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.
9. **Administrative Controls:** See Item 8, above.
10. **Operating Experience:** The program reviews industry experience regarding fatigue cracking. Applicable experience with fatigue cracking is to be considered in selecting the monitored locations.

## References

- NUREG/CR-5704, *Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels*, U.S. Nuclear Regulatory Commission, April 1999.
- NUREG/CR-6260, *Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components*, U.S. Nuclear Regulatory Commission, March 1995.
- NUREG/CR-6583, *Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels*, U.S. Nuclear Regulatory Commission, March 1998.

## XI.M17 FLOW-ACCELERATED CORROSION

### Program Description

The program relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R2 for an effective flow-accelerated corrosion (FAC) program. The program includes performing (a) an analysis to determine critical locations, (b) limited baseline inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm the predictions, or repairing or replacing components as necessary.

### Evaluation and Technical Basis

1. **Scope of Program:** The FAC program, described by the EPRI guidelines in NSAC-202L-R2, includes procedures or administrative controls to assure that the structural integrity of all carbon steel lines containing high-energy fluids (two phase as well as single phase) is maintained. Valve bodies retaining pressure in these high-energy systems are also covered by the program. The FAC program was originally outlined in NUREG-1344 and was further described through the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-08. A program implemented in accordance with the EPRI guidelines predicts, detects, and monitors FAC in plant piping and other components, such as valve bodies, elbows and expanders. Such a program includes the following recommendations: (a) conducting an analysis to determine critical locations, (b) performing limited baseline inspections to determine the extent of thinning at these locations, and (c) performing follow-up inspections to confirm the predictions, or repairing or replacing components as necessary. NSAC-202L-R2 (April 1999) provides general guidelines for the FAC program. To ensure that all the aging effects caused by FAC are properly managed, the program includes the use of a predictive code, such as CHECWORKS, that uses the implementation guidance of NSAC-202L-R2 to satisfy the criteria specified in 10 CFR Part 50, Appendix B, criteria for development of procedures and control of special processes.
2. **Preventive Actions:** The FAC program is an analysis, inspection, and verification program; thus, there is no preventive action. However, it is noted that monitoring of water chemistry to control pH and dissolved oxygen content, and selection of appropriate piping material, geometry, and hydrodynamic conditions, are effective in reducing FAC.
3. **Parameters Monitored/Inspected:** The aging management program (AMP) monitors the effects of FAC on the intended function of piping and components by measuring wall thickness.
4. **Detection of Aging Effects:** Degradation of piping and components occurs by wall thinning. The inspection program delineated in NSAC-202L-R2 consists of identification of susceptible locations as indicated by operating conditions or special considerations. Ultrasonic and radiographic testing is used to detect wall thinning. The extent and schedule of the inspections assure detection of wall thinning before the loss of intended function.
5. **Monitoring and Trending:** CHECWORKS or a similar predictive code is used to predict component degradation in the systems conducive to FAC, as indicated by specific plant data, including material, hydrodynamic, and operating conditions. CHECWORKS is

acceptable because it provides a bounding analysis for FAC. CHECWORKS was developed and benchmarked by using data obtained from many plants. The inspection schedule developed by the licensee on the basis of the results of such a predictive code provides reasonable assurance that structural integrity will be maintained between inspections. Inspection results are evaluated to determine if additional inspections are needed to assure that the extent of wall thinning is adequately determined, assure that intended function will not be lost, and identify corrective actions.

6. **Acceptance Criteria:** Inspection results are input for a predictive computer code, such as CHECWORKS, to calculate the number of refueling or operating cycles remaining before the component reaches the minimum allowable wall thickness. If calculations indicate that an area will reach the minimum allowed wall thickness before the next scheduled outage, the component is to be repaired, replaced, or reevaluated.
7. **Corrective Actions:** Prior to service, components for which the acceptance criteria are not satisfied are reevaluated, repaired, or replaced. Long-term corrective actions could include adjusting operating parameters or selecting materials resistant to FAC. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.
8. **Confirmation Process:** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.
9. **Administrative Controls:** See Item 8, above.
10. **Operating Experience:** Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems (NRC IE Bulletin No. 87-01; NRC Information Notices [INs] 81-28, 92-35, 95-11) and in two-phase piping in extraction steam lines (NRC INs 89-53, 97-84) and moisture separation reheater and feedwater heater drains (NRC INs 89-53, 91-18, 93-21, 97-84). Operating experience shows that the present program, when properly implemented, is effective in managing FAC in high-energy carbon steel piping and components.

## References

- 10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.
- 10 CFR Part 50.55a, Codes and Standards, Office of the Federal Register, National Archives and Records Administration, 2005.
- NRC Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning*, U.S. Nuclear Regulatory Commission, May 2, 1989.
- NRC IE Bulletin 87-01, *Thinning of Pipe Walls in Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, July 9, 1987.

NRC Information Notice 81-28, *Failure of Rockwell-Edward Main Steam Isolation Valves*, U.S. Nuclear Regulatory Commission, September 3, 1981.

NRC Information Notice 89-53, *Rupture of Extraction Steam Line on High Pressure Turbine*, U.S. Nuclear Regulatory Commission, June 13, 1989.

NRC Information Notice 91-18, *High-Energy Piping Failures Caused by Wall Thinning*, U.S. Nuclear Regulatory Commission, March 12, 1991.

NRC Information Notice 91-18, Supplement 1, *High-Energy Piping Failures Caused by Wall Thinning*, U.S. Nuclear Regulatory Commission, December 18, 1991.

NRC Information Notice 92-35, *Higher than Predicted Erosion/Corrosion in Unisolable Reactor Coolant Pressure Boundary Piping inside Containment at a Boiling Water Reactor*, U.S. Nuclear Regulatory Commission, May 6, 1992.

NRC Information Notice 93-21, *Summary of NRC Staff Observations Compiled during Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs*, U.S. Nuclear Regulatory Commission, March 25, 1993.

NRC Information Notice 95-11, *Failure of Condensate Piping Because of Erosion/Corrosion at a Flow Straightening Device*, U.S. Nuclear Regulatory Commission, February 24, 1995.

NRC Information Notice 97-84, *Rupture in Extraction Steam Piping as a Result of Flow-Accelerated Corrosion*, U.S. Nuclear Regulatory Commission, December 11, 1997.

NSAC-202L-R2, *Recommendations for an Effective Flow Accelerated Corrosion Program*, Electric Power Research Institute, Palo Alto, CA, April 8, 1999.

NUREG-1344, *Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants*, P. C. Wu, U.S. Nuclear Regulatory Commission, April 1989.

## XI.M18 BOLTING INTEGRITY

### Program Description

The program relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, and industry recommendations, as delineated in the Electric Power Research Institute (EPRI) NP-5769, with the exceptions noted in NUREG-1339 for safety-related bolting. The program relies on industry recommendations for comprehensive bolting maintenance, as delineated in EPRI TR-104213 for pressure retaining bolting and structural bolting.

The program generally includes periodic inspection of closure bolting for indication of loss of preload, cracking, and loss of material due to corrosion, rust, etc. The program also includes preventive measures to preclude or minimize loss of preload and cracking.

Other aging management programs, such as XI.M1, "ASME Section XI Inservice Inspection (ISI) Subsections IWB, IWC, and IWD" and XI.S3, "ASME Section XI Subsection IWF" also manage inspection of safety-related bolting and supplement this bolting integrity program.

### Evaluation and Technical Basis

1. **Scope of Program:** This program covers bolting within the scope of license renewal, including: 1) safety-related bolting, 2) bolting for nuclear steam supply system (NSSS) component supports, 3) bolting for other pressure retaining components, including non-safety-related bolting, and 4) structural bolting (actual measured yield strength  $\geq 150$  ksi). The aging management of reactor head closure studs is addressed by XI.M3, and is not included in this program. The staff's recommendations and guidelines for comprehensive bolting integrity programs that encompass all safety-related bolting are delineated in NUREG-1339, which include the criteria established in the 1995 edition through the 1996 addenda of ASME Code Section XI. The industry's technical basis for the program for safety-related bolting and guidelines for material selection and testing, bolting preload control, ISI, plant operation, and maintenance, and evaluation of the structural integrity of bolted joints, are outlined in EPRI NP-5769, with the exceptions noted in NUREG-1339. For other bolting, this information is set forth in EPRI TR-104213.
2. **Preventive Actions:** Selection of bolting material and the use of lubricants and sealants is in accordance with the guidelines of EPRI NP-5769, and the additional recommendations of NUREG-1339, to prevent or mitigate degradation and failure of safety-related bolting (see element 10, below). NUREG-1339 takes exception to certain items in EPRI NP-5769, and recommends additional measures with regard to them. Bolting replacement activities include proper torquing of the bolts and checking for uniformity of the gasket compression after assembly. Maintenance practices require the application of an appropriate preload, based on EPRI documents.
3. **Parameters Monitored/Inspected:** This program monitors the effects of aging on the intended function of bolting. Specifically, bolting for safety-related pressure retaining components is inspected for leakage, loss of material, cracking, and loss of preload/loss of prestress. Bolting for other pressure retaining components is inspected for signs of leakage.

High strength bolts (actual yield strength  $\geq 150$  ksi) used in NSSS component supports are monitored for cracking. Structural bolts and fasteners are inspected for indication of potential problems including loss of material, cracking, loss of coating integrity, and obvious signs of corrosion, rust, etc.

4. **Detection of Aging Effects:** Inspection requirements are in accordance with the ASME Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1 editions endorsed in 10 CFR 50.55a(b)(2) and the recommendations of EPRI NP-5769. For Class 1 components, Table IWB 2500-1, Examination Category B-G-1, for bolts greater than 2-inches in diameter, specifies volumetric examination of studs and bolts and visual VT-1 examination of surfaces of nuts, washers, bushings, and flanges. Examination Category B-G-2, for bolts 2-inches or smaller, requires only visual VT-1 examination of surfaces of bolts, studs, and nuts. For Class 2 components, Table IWC 2500-1, Examination Category C-D, for bolts greater than 2-inches in diameter, requires volumetric examination of studs and bolts. Examination Categories B-P, C-H, and D-B require visual examination (IWA-5240) during system leakage testing of all pressure-retaining Class 1, 2 and 3 components, according to Tables IWB 2500-1, IWC 2500-1, and IWD 2500-1, respectively. In addition, degradation of the closure bolting due to crack initiation, loss of prestress, or loss of material due to corrosion of the closure bolting would result in leakage. The extent and schedule of inspections, in accordance with Tables IWB 2500-1, IWC 2500-1, and IWD 2500-1, combined with periodic system walkdowns, assure detection of leakage before the leakage becomes excessive.

For other pressure retaining bolting, periodic system walkdowns assure detection of leakage before the leakage becomes excessive.

High strength structural bolts and fasteners (actual yield strength 150 ksi) for NSSS component supports, may be subject to stress corrosion cracking (SCC). For this type of high strength structural bolts that are potentially subjected to SCC, in sizes greater than 1-inch nominal diameter, volumetric examination comparable to that of Examination Category B-G-1 is required in addition to visual examination. This requirement may be waived with adequate plant-specific justification. Structural bolts and fasteners (actual yield strength  $< 150$  ksi) both inside and outside containment are inspected by visual inspection (e.g., Structures Monitoring Program or equivalent). In addition to visual and volumetric examination, degradation of these bolts and fasteners may be detected and measured by removing the bolt/fastener, a proof test by tension or torquing, in situ ultrasonic tests, or a hammer test. If these bolts and fasteners are found cracked and/or corroded, a closer inspection is performed to assess extent of corrosion. An appropriate technique is selected on the basis of the bolting application and the applicable code.

5. **Monitoring and Trending:** The inspection schedules of ASME Section XI are effective and ensure timely detection of applicable aging effects. If bolting connections for pressure retaining components (not covered by ASME Section XI) is reported to be leaking, then it may be inspected daily. If the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly.
6. **Acceptance Criteria:** Any indications of aging effects in ASME pressure retaining bolting are evaluated in accordance with Section XI of the ASME Code. For other pressure retaining bolting, NSSS component support bolting and structural bolting, indications of aging should be dispositioned in accordance with the corrective action process.

7. **Corrective Actions:** Replacement of ASME pressure retaining bolting is performed in accordance with appropriate requirements of Section XI of the ASME Code, as subject to the additional guidelines and recommendations of EPRI NP-5769. Replacement of other pressure retaining bolting (i.e., non-Class 1 bolting) and disposition of degraded structural bolting is performed in accordance with the guidelines and recommendations of EPRI TR-104213. Replacement of NSSS component support bolting is performed in accordance with EPRI NP-5769. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.
8. **Confirmation Process:** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.
9. **Administrative Controls:** See item 8, above.
10. **Operating Experience:** Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, SCC, and fatigue loading (NRC IE Bulletin 82-02, NRC Generic Letter 91-17). SCC has occurred in high strength bolts used for NSSS component supports (EPRI NP-5769). The bolting integrity program developed and implemented in accordance with commitments made in response to NRC communications on bolting events have provided an effective means of ensuring bolting reliability. These programs are documented in EPRI NP-5769 and TR-104213 and represent industry consensus.

Degradation related failures have occurred in downcomer Tee-quencher bolting in BWRs designed with drywells (ADAMS Accession Number ML050730347). Leakage from bolted connections has been observed in reactor building closed cooling systems of BWRs. (LER 50-341/2005-001).

The applicant is to evaluate applicable operating experience to support the conclusion that the effects of aging are adequately managed.

## References

- 10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.
- 10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2005.
- ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2001 edition including the 2002 and 2003 Addenda, American Society of Mechanical Engineers, New York, NY.
- EPRI NP-5769, *Degradation and Failure of Bolting in Nuclear Power Plants*, Volumes 1 and 2, April 1988.
- EPRI TR-104213, *Bolted Joint Maintenance & Application Guide*, Electric, December 1995.



NRC Generic Letter 91-17, *Generic Safety Issue 79, Bolting Degradation or Failure in Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, October 17, 1991.

NRC IE Bulletin No. 82-02, *Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants*, U.S. Nuclear Regulatory Commission, June 2, 1982.

NUREG-1339, *Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, June 1990.

*Failure of Safety/Relief Valve Tee-Quencher Support Bolts*, NRC Morning Report for March 14, 2005, ADAMS Accession Number ML050730347.

## XI.M19 STEAM GENERATOR TUBE INTEGRITY

### Program Description

The steam generator tube integrity program is applicable to managing the aging of steam generator tubes, plugs, sleeves and tube supports.

Mill annealed alloy 600 steam generator (SG) tubes have experienced tube degradation related to corrosion phenomena, such as primary water stress corrosion cracking (PWSCC), outside diameter stress corrosion cracking (ODSCC), intergranular attack (IGA), pitting, and wastage, along with other mechanically induced phenomena, such as denting, wear, impingement damage, and fatigue. The dominant degradation mode at this time for thermally treated alloy 600 and 690 tubes is wear. Nondestructive examination (NDE) techniques are used to inspect all tubing materials and sleeves to identify tubes with degradation that may need to be removed from service or repaired in accordance with plant technical specifications. In addition, operational leakage limits are included to ensure that, should substantial tube leakage develop, prompt action is taken. These limits are included in plant technical specifications, such as standard technical specifications of NUREG-1430, Rev. 1, for Babcock & Wilcox pressurized water reactors (PWRs); NUREG-1431, Rev. 1, for Westinghouse PWRs; and NUREG-1432, Rev. 1, for Combustion Engineering PWRs.

The technical specifications specify SG inspection scope, frequency, and acceptance criteria for the plugging and repair of flawed tubes. NRC Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded Steam Generator Tubes," provides guidelines for determining the tube repair criteria and operational leakage limits. Acceptance criteria for the plugging and repair of flawed tubes are incorporated in plant technical specifications. In addition to flaw acceptance (or plugging/repair) criteria, the technical specifications also specify acceptable tube repair methods (e.g., plugging and/or sleeving). Plants may also apply for changes in their technical specifications to provide an alternate repair criteria for SG degradation management.

In addition to plant technical specifications, all PWR licensees have committed voluntarily to a SG degradation management program described in the Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines." This program references a number of industry guidelines and incorporates a balance of prevention, inspection, evaluation, repair, and leakage monitoring measures. The NEI 97-06 document (a) includes performance criteria that are intended to provide assurance that tube integrity is being maintained consistent with the plant's licensing basis, and (b) provides guidance for monitoring and maintaining the tubes to provide assurance that the performance criteria are met at all times between scheduled inspections of the tubes. Steam generator tube integrity can be affected by degradation of SG plugs, sleeves and tube supports. Therefore, these components are also addressed by this aging management program.

The NEI 97-06 program includes an assessment of degradation mechanisms that considers operating experience from similar steam generators (SGs) and, for each mechanism, defines the inspection techniques as well as the sampling strategy. The industry guidelines provide criteria for the qualification of personnel, specific techniques, and the associated acquisition and analysis of data, including procedures, probe selection, analysis protocols, and reporting criteria. The performance criteria pertain to structural integrity, accident-induced leakage, and operational leakage. The SG monitoring program includes guidance on assessment of degradation mechanisms, inspection, tube integrity assessment, maintenance, plugging, repair, and leakage monitoring, as well as procedures for monitoring and controlling secondary-side

and primary-side water chemistry. The water chemistry program for PWRs relies on monitoring and control of reactor water chemistry and secondary water chemistry.

Lastly, NRC Generic Letter (GL) 97-06, "Degradation of Steam Generator Internals," dated December 30, 1997, notified the industry of various steam generator tube support plate damage mechanisms identified in foreign and domestic steam generators. In response to GL 97-06, licensees indicated whether they had a program in place to detect degradation of steam generator internals, and included a description of the inspection plans, including the inspection scope, frequency, methods, and components.

As evaluated below, the plant technical specifications, including alternate repair criteria for SG degradation management that have been previously approved by the staff for that plant, the licensee's response to GL 97-06, and the licensee's commitment to implement the SG degradation management program described in NEI 97-06, are adequate to manage the effects of aging on the SG tubes, plugs, sleeves, and tube supports.

### Evaluation and Technical Basis

1. **Scope of Program:** The scope of the program is specific to SG tubes, plugs, sleeves and tube supports. The program includes preventive measures to mitigate degradation related to corrosion phenomena, assessment of degradation mechanisms, inservice inspection (ISI) of steam generator tubes, plugs, sleeves, and tube supports to detect degradation, evaluation, and plugging or repair, as needed, and leakage monitoring to maintain the structural and leakage integrity of the pressure boundary. Tube and sleeve inspection scope and frequency, plugging or repair, and leakage monitoring are in accordance with the plant technical specifications and the licensee's SG degradation management program implemented in accordance with NEI 97-06. Plug inspection scope and frequency, plugging or repair, and leakage monitoring are in accordance with the licensee's SG degradation management program implemented in accordance with NEI 97-06. Lastly, tube support plate inspection scope and frequency are in accordance with the licensee's SG degradation management program implemented in accordance with NEI 97-06 as well as the program described in the licensee's response to GL 97-06.
2. **Preventive Actions:** The program includes preventive measures to mitigate degradation related to corrosion phenomena. The guidelines in NEI 97-06 include foreign material exclusion as a means to inhibit wear degradation. The water chemistry program for PWRs relies on monitoring and control of reactor water chemistry based on the EPRI guidelines in TR-05714 for primary water chemistry and TR-102134 for secondary water chemistry. The program description and the evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, "Water Chemistry," of this report.
3. **Parameters Monitored/Inspected:** The inspection activities in the program detect flaws in tubing, plugs, sleeving, and degradation of tube supports needed to maintain tube integrity. Tubes are repaired or removed from service based on technical specification repair criteria. Sleeves are removed from service based on technical specification repair criteria. Degraded plugs and tube supports are evaluated for corrective actions.
4. **Detection of Aging Effects:** The inspection requirements in the technical specifications are intended to detect tube and sleeve degradation (i.e., aging effects), if they should occur. NEI 97-06 provides additional guidance on inspection programs to detect

degradation of tubes, sleeves, plugs and tube supports. The intent of the inspection and repair criteria is to provide assurance of continued tube integrity between inspections. A licensee's response to GL 97-06 also provides a description of plant-specific inspection programs for detection of degraded SG internals.

5. **Monitoring and Trending:** Condition monitoring assessments are performed to determine whether structural and accident leakage criteria have been satisfied. Operational assessments are performed after inspections to verify that structural and leakage integrity will be maintained for the operating interval between inspections, which is selected in accordance with the technical specifications and NEI 97-06 guidelines. Comparison of the results of the condition monitoring assessment with the predictions of the previous operational assessment provides feedback for evaluation of the adequacy of the operational assessment and additional insights that can be incorporated into the next operational assessment.
6. **Acceptance Criteria:** Assessment of tube and sleeve integrity and plugging or repair criteria of flawed and sleeved tubes is in accordance with plant technical specifications. The criteria for plugging or repairing SG tubes and sleeves are based on NRC RG 1.121 or other criteria previously reviewed and approved by the staff and incorporated into plant technical specifications. Some examples of acceptance criteria that are applicable under certain circumstances include F\*, L\*, or NRC Generic Letter (GL) 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside-Diameter Stress-Corrosion Cracking."
7. **Corrective Actions:** Tubes and sleeves containing flaws that do not meet the acceptance criteria are plugged or repaired. Degraded plugs and tube supports are evaluated for corrective actions. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.
8. **Confirmation Process:** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.
9. **Administrative Controls:** See Item 8, above.
10. **Operating Experience:** Failures to detect some flaws, uncertainties in flaw sizing, inaccuracies in flaw locations, and the inability to detect some cracks at locations with dents have been reviewed in NRC Information Notice (IN) 97-88. Recent experience indicates the importance of performing a complete inspection by using appropriate techniques and components for the reliable detection of tube degradation and to provide assurance that new forms of degradation are detected. Implementation of the program provides reasonable assurance that SG tube integrity is maintained consistent with the plants' licensing basis for the period of extended operation. Experience with the condition monitoring and operational assessments required for plants that have implemented the alternate repair criteria in NRC GL 95-05 has shown that the predictions of the operational assessments have generally been consistent with the results of the subsequent condition monitoring assessments. In cases where discrepancies have been noted, adjustments have been made in the operational assessment models to improve agreement in

subsequent assessments. In addition, the industry has programs/processes for incorporating lessons learned from plant operation into guidelines referenced in NEI 97-06.

## References

- 10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.
- 10 CFR Part 50.55a, Codes and Standards, Office of the Federal Register, National Archives and Records Administration, 2005.
- EPRI TR-102134, *PWR Secondary Water Chemistry Guidelines: Revision 3*, Electric Power Research Institute, Palo Alto, CA, May 1993.
- EPRI TR-105714, *PWR Primary Water Chemistry Guidelines: Revision 3*, Electric Power Research Institute, Palo Alto, CA, November 1995.
- EPRI TR-107569, *PWR Steam Generator Examination Guidelines: Revision 6*, Electric Power Research Institute, Palo Alto, CA, October 2002.
- NEI 97-06, Rev. 1, *Steam Generator Program Guidelines*, Nuclear Energy Institute, January 2001.
- NRC Generic Letter 95-05, *Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside-Diameter Stress-Corrosion Cracking*, U.S. Nuclear Regulatory Commission, August 3, 1995.
- NRC Generic Letter 97-06, *Degradation of Steam Generator Internals*, U.S. Nuclear Regulatory Commission, December 30, 1997.
- NRC Information Notice, 97-88, *Experiences during Recent Steam Generator Inspections*, U.S. Nuclear Regulatory Commission, December 12, 1997.
- NRC Regulatory Guide, 1.83, Rev. 1, *Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes*, U.S. Nuclear Regulatory Commission, July 1975.
- NRC Regulatory Guide, 1.121, *Bases for Plugging Degraded PWR Steam Generator Tubes*, U.S. Nuclear Regulatory Commission, August 1976.
- NUREG-1430, Rev. 1, *Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors*, U.S. Nuclear Regulatory Commission, April 1995.
- NUREG-1431, Rev. 1, *Standard Technical Specifications for Westinghouse Pressurized Water Reactors*, U.S. Nuclear Regulatory Commission, April 1995.
- NUREG-1432, Rev. 1, *Standard Technical Specifications for Combustion Engineering Pressurized Water Reactors*, U.S. Nuclear Regulatory Commission, April 1995.

## XI.M20 OPEN-CYCLE COOLING WATER SYSTEM

### Program Description

The program relies on implementation of the recommendations of the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-13 to ensure that the effects of aging on the open-cycle cooling water (OCCW) (or service water) system will be managed for the extended period of operation. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the OCCW system or structures and components serviced by the OCCW system.

### Evaluation and Technical Basis

1. **Scope of Program:** The program addresses the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms. Because the characteristics of the service water system may be specific to each facility, the OCCW system is defined as a system or systems that transfer heat from safety-related systems, structures, and components (SSC) to the ultimate heat sink (UHS). If an intermediate system is used between the safety-related SSCs and the system rejecting heat to the UHS, that intermediate system performs the function of a service water system and is thus included in the scope of recommendations of NRC GL 89-13. The guidelines of NRC GL 89-13 include (a) surveillance and control of biofouling; (b) a test program to verify heat transfer capabilities; (c) routine inspection and a maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of safety-related systems serviced by OCCW; (d) a system walk down inspection to ensure compliance with the licensing basis; and (e) a review of maintenance, operating, and training practices and procedures.
2. **Preventive Actions:** The system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments. Implementation of NRC GL 89-13 includes a condition and performance monitoring program; control or preventive measures, such as chemical treatment, whenever the potential for biological fouling species exists; or flushing of infrequently used systems. Treatment with chemicals mitigates microbiologically-influenced corrosion (MIC) and buildup of macroscopic biological fouling species, such as blue mussels, oysters, or clams. Periodic flushing of the system removes accumulations of biofouling agents, corrosion products, and silt.
3. **Parameters Monitored/Inspected:** Adverse effects on system or component performance are caused by accumulations of biofouling agents, corrosion products, and silt. Cleanliness and material integrity of piping, components, heat exchangers, elastomers, and their internal linings or coatings (when applicable) that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure heat transfer capabilities. The program ensures (a) removal of accumulations of biofouling agents, corrosion products, and silt, and (b) detection of defective protective coatings and corroded OCCW system piping and components that could adversely affect performance of their intended safety functions.
4. **Detection of Aging Effects:** Inspections for biofouling, damaged coatings, and degraded material condition are conducted. Visual inspections are typically performed; however, nondestructive testing, such as ultrasonic testing, eddy current testing, and heat transfer

capability testing, are effective methods to measure surface condition and the extent of wall thinning associated with the service water system piping and components, when determined necessary.

5. **Monitoring and Trending:** Inspection scope, method (e.g., visual or nondestructive examination [NDE]), and testing frequencies are in accordance with the utility commitments under NRC GL 89-13. Testing and inspections are done annually and during refueling outages. Inspections or nondestructive testing will determine the extent of biofouling, the condition of the surface coating, the magnitude of localized pitting, and the amount of MIC, if applicable. Heat transfer testing results are documented in plant test procedures and are trended and reviewed by the appropriate group.
6. **Acceptance Criteria:** Biofouling is removed or reduced as part of the surveillance and control process. The program for managing biofouling and aggressive cooling water environments for OCCW systems is preventive. Acceptance criteria are based on effective cleaning of biological fouling organisms and maintenance of protective coatings or linings are emphasized.
7. **Corrective Actions:** Evaluations are performed for test or inspection results that do not satisfy established acceptance criteria and a problem or condition report is initiated to document the concern in accordance with plant administrative procedures. The corrective actions program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined, and an action plan is developed to preclude repetition. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.
8. **Confirmation Process:** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.
9. **Administrative Controls:** See Item 8, above.
10. **Operating Experience:** Significant microbiologically-influenced corrosion (NRC Information Notice [IN] 85-30), failure of protective coatings (NRC IN 85-24), and fouling (NRC IN 81-21, IN 86-96) have been observed in a number of heat exchangers. The guidance of NRC GL 89-13 has been implemented for approximately 10 years and has been effective in managing aging effects due to biofouling, corrosion, erosion, protective coating failures, and silting in structures and components serviced by OCCW systems.

## References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, July 18, 1989.

NRC Generic Letter 89-13, Supplement 1, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, April 4, 1990.

NRC Information Notice 81-21, *Potential Loss of Direct Access to Ultimate Heat Sink*, U.S. Nuclear Regulatory Commission, July 21, 1981.

NRC Information Notice 85-24, *Failures of Protective Coatings in Pipes and Heat Exchangers*, U.S. Nuclear Regulatory Commission, March 26, 1985.

NRC Information Notice 85-30, *Microbiologically Induced Corrosion of Containment Service Water System*, U.S. Nuclear Regulatory Commission, April 19, 1985.

NRC Information Notice 86-96, *Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems*, U.S. Nuclear Regulatory Commission, November 20, 1986.



## XI.M21 CLOSED-CYCLE COOLING WATER SYSTEM

### Program Description

The program includes (a) preventive measures to minimize corrosion and stress corrosion cracking (SCC) and (b) testing and inspection to monitor the effects of corrosion and SCC on the intended function of the component. The program relies on maintenance of system corrosion inhibitor concentrations within the specified limits of Electric Power Research Institute (EPRI) TR-107396 to minimize corrosion and SCC. Non-chemistry monitoring techniques such as testing and inspection in accordance with guidance in EPRI TR-107396 for closed-cycle cooling water (CCCW) systems provide one acceptable method to evaluate system and component performance. These measures will ensure that the intended functions of the CCCW system and components serviced by the CCCW system are not compromised by aging.

### Evaluation and Technical Basis

1. **Scope of Program:** A CCCW system is defined as part of the service water system that is not subject to significant sources of contamination, in which water chemistry is controlled and in which heat is not directly rejected to a heat sink. The program described in this section applies only to such a system. If one or more of these conditions are not satisfied, the system is to be considered an open-cycle cooling water system. The staff notes that if the adequacy of cooling water chemistry control cannot be confirmed, the system is treated as an open-cycle system as indicated in Action III of Generic Letter (GL) 89-13.
2. **Preventive Actions:** The program relies on the use of appropriate materials, lining, or coating to protect the underlying metal surfaces and maintain system corrosion inhibitor concentrations within the specified limits of EPRI TR-107396 to minimize corrosion and SCC. The program includes monitoring and control of cooling water chemistry to minimize exposure to aggressive environments and application of corrosion inhibitor in the CCCW system to mitigate general, crevice, and pitting corrosion as well as SCC.
3. **Parameters Monitored/Inspected:** The aging management program monitors the effects of corrosion and SCC by testing and inspection in accordance with guidance in EPRI TR-107396 to evaluate system and component condition. For pumps, the parameters monitored include flow, discharge pressures, and suction pressures. For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure.
4. **Detection of Aging Effects:** Control of water chemistry does not preclude corrosion or SCC at locations of stagnant flow conditions or crevices. Degradation of a component due to corrosion or SCC would result in degradation of system or component performance. The extent and schedule of inspections and testing should assure detection of corrosion or SCC before the loss of the intended function of the component. Performance and functional testing ensures acceptable functioning of the CCCW system or components serviced by the CCCW system. For systems and components in continuous operation, performance adequacy should be verified by monitoring component performance through data trends for evaluation of heat transfer capability, system branch flow changes and chemistry data trends. Components not normally in operation are periodically tested to ensure operability.

5. **Monitoring and Trending:** The frequency of sampling water chemistry varies and can occur on a continuous, daily, weekly, or as needed basis, as indicated by plant operating conditions and the type of chemical treatment. In accordance with EPRI TR-107396, internal visual inspections and performance/functional tests are to be performed periodically to demonstrate system operability and confirm the effectiveness of the program. Tests to evaluate heat removal capability of the system and degradation of system components may also be used. The testing intervals should be established based on plant-specific considerations such as system conditions, trending, and past operating experience, and may be adjusted based on the results of a reliability analysis, type of service, frequency of operation, or age of components and systems.
6. **Acceptance Criteria:** Corrosion inhibitor concentrations are maintained within the limits specified in the EPRI water chemistry guidelines for CCCW. System and component performance test results are evaluated in accordance with system and component design basis requirements. Acceptance criteria and tolerances are to be based on system design parameters and functions.
7. **Corrective Actions:** Corrosion inhibitor concentrations outside the allowable limits are returned to the acceptable range within the time period specified in the EPRI water chemistry guidelines for CCCW. If the system or component fails to perform adequately, corrective actions are taken. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.
8. **Confirmation Process:** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.
9. **Administrative Controls:** See Item 8, above.
10. **Operating Experience:** Degradation of closed-cycle cooling water systems due to corrosion product buildup (NRC Licensee Event Report [LER] 50-327/93-029-00) or through-wall cracks in supply lines (NRC 50-280/91-019-00) has been observed in operating plants. Accordingly, operating experience demonstrates the need for this program.

## References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

EPRI TR-107396, *Closed Cooling Water Chemistry Guidelines*, Electric Power Research Institute, Palo Alto, CA, October 1997.

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, July 18, 1989.

NRC Generic Letter 89-13, Supplement 1, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, April 4, 1990.

NRC Licensee Event Report LER 50-280/91-019-00, *Loss of Containment Integrity due to Crack in Component Cooling Water Piping*, October 26, 1991.

NRC Licensee Event Report LER 50-327/93-029-00, *Inoperable Check Valve in the Component Cooling System as a Result of a Build-Up of Corrosion Products between Valve Components*, December 13, 1993.

## XI.M22 BORAFLEX MONITORING

### Program Description

A Boraflex monitoring program for the actual Boraflex panels is implemented in the spent fuel racks to assure that no unexpected degradation of the Boraflex material would compromise the criticality analysis in support of the design of spent fuel storage racks. The applicable aging management program (AMP), based on manufacturer's recommendations, relies on periodic inspection, testing, monitoring, and analysis of the criticality design to assure that the required 5% subcriticality margin is maintained. The frequency of the inspection and testing depends on the condition of the Boraflex, with a maximum of five years. Certain accelerated samples are tested every two years. Results based on test coupons have been found to be unreliable in determining the degree to which the actual Boraflex panels have been degraded. Therefore, this AMP includes: (1) performing neutron attenuation testing, called blackness testing, to determine gap formation in Boraflex panels; (2) completing sampling and analysis for silica levels in the spent fuel pool water and trending the results by using the EPRI RACKLIFE predictive code or its equivalent on a monthly, quarterly, or annual basis (depending on Boraflex panel condition); and (3) measuring boron areal density by techniques such as the BADGER device. Corrective actions are initiated if the test results find that the 5% subcriticality margin cannot be maintained because of current or projected future Boraflex degradation.

### Evaluation and Technical Basis

1. **Scope of Program:** The AMP manages the effects of aging on sheets of neutron-absorbing materials affixed to spent fuel racks. For Boraflex panels, gamma irradiation and long-term exposure to the wet pool environment cause shrinkage resulting in gap formation, gradual degradation of the polymer matrix, and the release of silica to the spent fuel storage pool water. This results in the loss of boron carbide in the neutron absorber sheets.
2. **Preventive Actions:** For Boraflex panels, monitoring silica levels in the storage pool water, measuring gap formation by blackness testing, periodically measuring boron areal density, and applying predictive codes, are performed. These actions ensure that degradation of the neutron-absorbing material is identified and corrected so the spent fuel storage racks will be capable of performing their intended functions during the period of extended operation, consistent with current licensing basis (CLB) design conditions.
3. **Parameters Monitored/Inspected:** The parameters monitored include physical conditions of the Boraflex panels, such as gap formation and decreased boron areal density, and the concentration of the silica in the spent fuel pool. These are conditions directly related to degradation of the Boraflex material. When Boraflex is subjected to gamma radiation and long-term exposure to the spent fuel pool environment, the silicon polymer matrix becomes degraded and silica filler and boron carbide are released into the spent fuel pool water. As indicated in the Nuclear Regulatory Commission (NRC) Information Notice (IN) 95-38 and NRC Generic Letter (GL) 96-04, the loss of boron carbide (washout) from Boraflex is characterized by slow dissolution of silica from the surface of the Boraflex and a gradual thinning of the material. Because Boraflex contains about 25% silica, 25% polydimethyl siloxane polymer, and 50% boron carbide, sampling and analysis of the presence of silica in the spent fuel pool provide an indication of depletion of boron carbide from Boraflex; however, the degree to which Boraflex has degraded is ascertained through measurement of the boron areal density.

4. **Detection of Aging Effects:** The amount of boron carbide released from the Boraflex panel is determined through direct measurement of boron areal density and correlated with the levels of silica present with a predictive code. This is supplemented with detection of gaps through blackness testing and periodic verification of boron loss through areal density measurement techniques such as the BADGER device.
5. **Monitoring and Trending:** The periodic inspection measurements and analysis are to be compared to values of previous measurements and analysis to provide a continuing level of data for trend analysis.
6. **Acceptance Criteria:** The 5% subcriticality margin of the spent fuel racks is to be maintained for the period of extended operation.
7. **Corrective Actions:** Corrective actions are initiated if the test results find that the 5% subcriticality margin cannot be maintained because of the current or projected future degradation. Corrective actions consist of providing additional neutron-absorbing capacity by Boral or boron steel inserts, or other options, which are available to maintain a subcriticality margin of 5%. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.
8. **Confirmation Process:** Site quality assurance (QA) procedures, site review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.
9. **Administrative Controls:** See item 8, above.
10. **Operating Experience:** The NRC IN 87-43 addresses the problems of development of tears and gaps (average 1-2 in., with the largest 4 in.) in Boraflex sheets due to gamma radiation-induced shrinkage of the material. NRC INs 93-70 and 95-38 and NRC GL 96-04 address several cases of significant degradation of Boraflex test coupons due to accelerated dissolution of Boraflex caused by pool water flow through panel enclosures and high accumulated gamma dose. Two spent fuel rack cells with about 12 years of service have only 40% of the Boraflex remaining. In such cases, the Boraflex may be replaced by boron steel inserts or by a completely new rack system using Boral. Experience with boron steel is limited; however, the application of Boral for use in the spent fuel storage racks predates the manufacturing and use of Boraflex. The experience with Boraflex panels indicates that coupon surveillance programs are not reliable. Therefore, during the period of extended operation, the measurement of boron areal density correlated, through a predictive code, with silica levels in the pool water is verified. These monitoring programs provide assurance that degradation of Boraflex sheets is monitored, so that appropriate actions can be taken in a timely manner if significant loss of neutron-absorbing capability is occurring. These monitoring programs ensure that the Boraflex sheets will maintain their integrity and will be effective in performing its intended function.

## References

- 10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.
- BNL-NUREG-25582, *Corrosion Considerations in the Use of Boral in Spent Fuel Storage Pool Racks*, January 1979.
- EPRI NP-6159, *An Assessment of Boraflex Performance in Spent-Nuclear-Fuel Storage Racks*, Electric Power Research Institute, Palo Alto, CA, December 14, 1988.
- EPRI TR-101986, *Boraflex Test Results and Evaluation*, Electric Power Research Institute, Palo Alto, CA, March 1, 1993.
- EPRI TR-103300, *Guidelines for Boraflex Use in Spent-Fuel Storage Racks*, Electric Power Research Institute, Palo Alto, CA, December 1, 1993.
- NRC Generic Letter 96-04, *Boraflex Degradation in Spent Fuel Pool Storage Racks*, U.S. Nuclear Regulatory Commission, June 26, 1996.
- NRC Information Notice 87-43, *Gaps in Neutron Absorbing Material in High Density Spent Fuel Storage Racks*, U.S. Nuclear Regulatory Commission, September 8, 1987.
- NRC Information Notice 93-70, *Degradation of Boraflex Neutron Absorber Coupons*, U.S. Nuclear Regulatory Commission, September 10, 1993.
- NRC Information Notice 95-38, *Degradation of Boraflex Neutron Absorber in Spent Fuel Storage Racks*, U.S. Nuclear Regulatory Commission, September 8, 1995.
- NRC Regulatory Guide 1.26, Rev. 3, *Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants (for Comment)*, U.S. Nuclear Regulatory Commission, February 1976.

## XI.M23 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

### Program Description

Most commercial nuclear facilities have between 50 and 100 cranes. Many are industrial grade cranes, which meet the requirements of 29 CFR Volume XVII, Part 1910, and Section 1910.179. Most are not within the scope of 10 CFR 54.4, and therefore are not required to be part of the integrated plant assessment (IPA).

Normally, fewer than 10 cranes fall within the scope of 10 CFR 54.4.

The program demonstrates that testing and monitoring programs have been implemented and have ensured that the structures, systems, and components of these cranes are capable of sustaining their rated loads. This is their intended function during the period of extended operation. It is noted that many of the systems and components of these cranes perform an intended function with moving parts or with a change in configuration, or subject to replacement based on qualified life. In these instances, these types of crane systems and components are not within the scope of this aging management program (AMP). This program is primarily concerned with structural components that make up the bridge and trolley. NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," provides specific guidance on the control of overhead heavy load cranes.

### Evaluation and Technical Basis

1. **Scope of Program:** The program manages the effects of general corrosion on the crane and trolley structural components for those cranes that are within the scope of 10 CFR 54.4, and the effects of wear on the rails in the rail system.
2. **Preventive Actions:** No preventive actions are identified. The crane program is an inspection program.
3. **Parameters Monitored/Inspected:** The program evaluates the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes.
4. **Detection of Aging Effect:** Crane rails and structural components are visually inspected on a routine basis for degradation.
5. **Monitoring and Trending:** Monitoring and trending are not required as part of the crane inspection program.
6. **Acceptance Criteria:** Any significant visual indication of loss of material due to corrosion or wear is evaluated according to applicable industry standards and good industry practice. The crane may also have been designed to a specific Service Class as defined in the Crane Manufacturers Association of America, Inc. (CMAA) Specification #70 (or later revisions), or CMAA Specification #74 (or later revisions). The specification that was applicable at the time the crane was manufactured is used.

7. **Corrective Actions:** Site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.
8. **Confirmation Process:** See Item 7, above.
9. **Administrative Controls:** See Item 7, above.
10. **Operating Experience** There has been no history of corrosion-related degradation that has impaired cranes. Likewise, because cranes have not been operated beyond their design lifetime, there have been no significant fatigue-related structural failures.

#### References

- 10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.
- Crane Manufacturers Association of America, Inc., CMAA Specification No. 70, *Specifications for Electric Overhead Traveling Cranes*, 1970 (or later revisions)
- Crane Manufacturers Association of America, Inc., CMAA Specification No. 74, *Specifications for Top Running and Under Running Single Girder Electric Overhead Traveling Cranes*, 1974 (or later revisions)
- Electric Overhead Crane Institute, Inc
- NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, 1980.
- NRC Regulatory Guide 1.160, Rev. 2, *Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, March 1997.



## XI.M24 COMPRESSED AIR MONITORING

### Program Description

The program consists of inspection, monitoring, and testing of the entire system. This includes (a) frequent leak testing of valves, piping, and other system components, especially those made of carbon steel and stainless steel; and (b) preventive monitoring that checks air quality at various locations in the system to ensure that oil, water, rust, dirt, and other contaminants are kept within the specified limits. The aging management program (AMP) provides for timely corrective actions to ensure that the system is operating within specified limits.

The AMP is based on results of the plant owner's response to Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-14, augmented by previous NRC Information Notices (IN) 81-38, IN 87-28, and IN 87-28 S1, and by the Institute of Nuclear Power Operations Significant Operating Experience Report (INPO SOER) 88-01. The NRC GL 88-14, issued after several years of study of problems and failures of instrument air systems, recommends each holder of an operating license to perform an extensive design and operations review and verification of its instrument air system. The GL 88-14 also recommends the licensees to describe their program for maintaining proper instrument air quality. The AMP also incorporates provisions conforming to the guidance of the Electric Power Research Institute (EPRI) NP-7079, issued in 1990, to assist utilities in identifying and correcting system problems in the instrument air system and to enable them to maintain required industry safety standards. Subsequent to these initial actions by all plant licensees to implement an improved AMP, some utilities decided to replace their instrument air system with newer models and types of components. The EPRI then issued TR-108147, which addresses maintenance of the latest compressors and other instrument air system components currently in use at those plants. The American Society of Mechanical Engineers operations and maintenance standards and guides (ASME OMS/G-1998, Part 17) provides additional guidance to the maintenance of the instrument air system by offering recommended test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

### Evaluation and Technical Basis

1. **Scope of Program:** The program manages the effects of corrosion and the presence of unacceptable levels of contaminants on the intended function of the compressed air system. The AMP includes frequent leak testing of valves, piping, and other system components, especially those made of carbon steel and stainless steel, and a preventive maintenance program to check air quality at several locations in the system.
2. **Preventive Actions:** The system air quality is monitored and maintained in accordance with the plant owner's testing and inspection plans, which are designed to ensure that the system and components meet specified operability requirements. These requirements are prepared from consideration of manufacturer's recommendations for individual components and guidelines based on ASME OMS/G-1998, Part 17; ISA-S7.0.01-1996; EPRI NP-7079; and EPRI TR-108147. The preventive maintenance program addresses various aspects of the inoperability of air-operated components due to corrosion and the presence of oil, water, rust, and other contaminants.
3. **Parameters Monitored/Inspected:** Inservice inspection (ISI) and testing is performed to verify proper air quality and confirm that maintenance practices, emergency procedures,

and training are adequate to ensure that the intended function of the air system is maintained.

4. **Detection of Aging Effects:** Guidelines in EPRI NP-7079, EPRI TR-108147, and ASME OM-S/G-1998, Part 17, ensure timely detection of degradation of the compressed air system function. Degradation of the piping and any components would become evident by observation of excessive corrosion, by the discovery of unacceptable leakage rates, and by failure of the system or any item of components to meet specified performance limits.
5. **Monitoring and Trending:** Effects of corrosion and the presence of contaminants are monitored by visual inspection and periodic system and component tests, including leak rate tests on the system and on individual items of components. These tests verify proper operation by comparing measured values of performance with specified performance limits. Test data are analyzed and compared to data from previous tests to provide for timely detection of aging effects.
6. **Acceptance Criteria:** Acceptance criteria are established for the system and for individual components that contain specific limits or acceptance ranges based on design basis conditions and/or components vendor specifications. The testing results are analyzed to verify that the design and performance of the system is in accordance with its intended function.
7. **Corrective Actions:** Corrective actions are taken if any parameters are out of acceptable ranges, such as moisture content in the system air. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.
8. **Confirmation Process:** The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.
9. **Administrative Controls:** See Item 8, above.
10. **Operating Experience:** Potentially significant safety-related problems pertaining to air systems have been documented in NRC IN 81-38, IN 87-28, IN 87-28 S1 and license event report (LER) 50-237/94-005-3. Some of the systems that have been significantly degraded or have failed due to the problems in the air system include the decay heat removal, auxiliary feedwater, main steam isolation, containment isolation, and fuel pool seal system. As a result of NRC GL 88-14 and consideration of INPO SOER 88-01, EPRI NP-7079, and EPRI TR-108147, performance of air systems has improved significantly.

## References

- 10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

ASME OM-S/G-1998, Part 17, *Performance Testing of Instrument Air Systems Information Notice Light-Water Reactor Power Plants*, 1ISA-S7.0.1-1996, "Quality Standard for Instrument Air," American Society of Mechanical Engineers, New York, NY, 1998.

EPRI NP-7079, *Instrument Air System: A Guide for Power Plant Maintenance Personnel*, Electric Power Research Institute, Palo Alto, CA, December 1990.

EPRI/NMAC TR-108147, *Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079*, Electric Power Research Institute, Palo Alto, CA., March 1998.

INPO SOER 88-01, *Instrument Air System Failures*, May 18, 1988.

NRC Generic Letter 88-14, *Instrument Air Supply Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, August 8, 1988.

NRC Information Notice 81-38, *Potentially Significant Components Failures Resulting from Contamination of Air-Operated Systems*, U.S. Nuclear Regulatory Commission, December 17, 1981.

NRC Information Notice 87-28, *Air Systems Problems at U.S. Light Water Reactors*, U.S. Nuclear Regulatory Commission, June 22, 1987.

NRC Information Notice 87-28, Supplement 1, *Air Systems Problems at U.S. Light Water Reactors*, U.S. Nuclear Regulatory Commission, December 28, 1987.

NRC Licensee Event Report LER 50-237/94-005-3, *Manual Reactor Scram due to Loss of Instrument Air Resulting from Air Receiver Pipe Failure Caused by Improper Installation of Threaded Pipe during Initial Construction*, U.S. Nuclear Regulatory Commission, April 23, 1997.

## XI.M25 BWR REACTOR WATER CLEANUP SYSTEM

### Program Description

The program includes inservice inspection (ISI) and monitoring and control of reactor coolant water chemistry to manage the effects of stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) on the intended function of austenitic stainless steel (SS) piping in the reactor water cleanup (RWCU) system. Based on the Nuclear Regulatory Commission (NRC) criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG-0313, Rev. 2, and NRC Generic Letter (GL) 88-01. Coolant water chemistry is monitored and maintained in accordance with the Electric Power Research Institute (EPRI) guidelines in boiling water reactor vessel and internals project (BWRVIP) -29 (TR-103515) to minimize the potential of cracking due to SCC or IGSCC.

### Evaluation and Technical Basis

1. **Scope of Program:** Based on the NRC letter (September 15, 1995) on the screening criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG-0313, Rev. 2, and NRC GL 88-01 to monitor SCC or IGSCC and its effects on the intended function of austenitic SS piping. The screening criteria include:
  - a. Satisfactory completion of all actions requested in NRC GL 89-10,
  - b. No detection of IGSCC in RWCU welds inboard of the second isolation valves (ongoing inspection in accordance with the guidance in NRC GL 88-01), and
  - c. No detection of IGSCC in RWCU welds outboard of the second isolation valves after inspecting a minimum of 10% of the susceptible piping.

No IGSCC inspection is recommended for plants that meet all the above three criteria or that meet criterion (a) and piping is made of material that is resistant to IGSCC.

2. **Preventive Actions:** The comprehensive program outlined in NUREG-0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause SCC or IGSCC. These elements are a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. The program delineated in NUREG-0313 and NRC GL 88-01 includes recommendations regarding selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stresses, and monitoring and maintenance of coolant chemistry. The resistant materials are used for new and replacement components and include low-carbon grades of austenitic SS and weld metal, with a maximum carbon of 0.035 wt.% and a minimum ferrite of 7.5% in weld metal and cast austenitic stainless steel (CASS). Inconel 82 is the only commonly used nickel-base weld metal considered resistant to SCC; other nickel-alloys, such as Alloy 600, are evaluated on an individual basis. Special processes are used for existing as well as new and replacement components. These processes include solution heat treatment, heat sink welding, induction heating, and mechanical stress improvement.

The program delineated in NUREG-0313 and NRC GL 88-01 varies depending on the plant- specific reactor water chemistry to mitigate SCC or IGSCC.

3. **Parameters Monitored/Inspected:** The aging management program (AMP) monitors SCC or IGSCC of austenitic SS piping by detection and sizing of cracks by implementing the inspection guidelines delineated in the NRC screening criteria for the RWCU piping outboard of isolation valves. The following schedules are followed:

*Schedule A:* No inspection is required for plants that meet all three criteria set forth above, or if they meet only criterion (a). Piping is made of material that is resistant to IGSCC, as described above in preventive actions.

*Schedule B:* For plants that meet only criterion (a): Inspect at least 2% of the welds or two welds every refueling outage, whichever sample is larger.

*Schedule C:* For plants that do not meet criterion (a): Inspect at least 10% of the welds every refueling outage.

4. **Detection of Aging Effects:** The extent, method, and schedule of the inspection and test techniques delineated in the NRC inspection criteria for RWCU piping and NRC GL 88-01 are designed to maintain structural integrity and to detect aging effects before the loss of intended function of austenitic SS piping and fittings. Guidelines for the inspection schedule, methods, personnel, sample expansion, and leak detection guidelines are based on the guidelines of NRC GL 88-01.

NRC GL 88-01 recommends that the detailed inspection procedure, components, and examination personnel be qualified by a formal program approved by the NRC. Inspection can reveal cracking and leakage of coolant. The extent and frequency of inspections recommended by the program are based on the condition of each weld (e.g., whether the weldments were made from IGSCC-resistant material, whether a stress improvement process was applied to a weldment to reduce the residual stresses, and how the weld was repaired if it had been cracked).

5. **Monitoring and Trending:** The extent and schedule for inspection in accordance with the recommendations of NRC GL 88-01 provide timely detection of cracks and leakage of coolant. Based on inspection results, NRC GL 88-01 provides guidelines for additional samples of welds to be inspected when one or more cracked welds are found in a weld category.
6. **Acceptance Criteria:** The NRC GL 88-01 recommends that any indication detected be evaluated in accordance with the requirements of ASME Section XI, Subsection IWB-3640 (2001 edition<sup>8</sup> including the 2002 and 2003 Addenda).
7. **Corrective Actions:** The guidance for weld overlay repair, stress improvement, or replacement is provided in NRC GL 88-01. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.
8. **Confirmation Process:** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with requirements.

<sup>8</sup> An applicant may rely on a different version of the ASME Code, but should justify such use. An applicant may wish to refer to the SOC for an update of 10 CFR § 50.55a to justify use of a more recent edition of the Code.

of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. **Administrative Controls:** See Item 8, above.
10. **Operating Experience:** The IGSCC has occurred in small- and large-diameter boiling water reactor (BWR) piping made of austenitic stainless steels or nickel alloys. The comprehensive program outlined in NRC GL 88-01 and NUREG-0313 addresses improvements in all elements that cause SCC or IGSCC (e.g., susceptible material, significant tensile stress, and an aggressive environment) and is effective in managing IGSCC in austenitic SS piping in the RWCU system.

## References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2001 edition including the 2002 and 2003 Addenda, American Society of Mechanical Engineers, New York, NY.

BWRVIP-29 (EPRI TR-103515), *BWR Vessel and Internals Project, BWR Water Chemistry Guidelines-1993 Revision, Normal and Hydrogen Water Chemistry*, Electric Power Research Institute, Palo Alto, CA, February 1994.

Letter from Joseph W. Shea, U.S. Nuclear Regulatory Commission, to George A. Hunter, Jr., PECO Energy Company, *Reactor Water Cleanup (RWCU) System Weld Inspections at Peach Bottom Atomic Power Station, Units 2 and 3 (TAC Nos. M92442 and M92443)*, September 15, 1995.

NRC Generic Letter 89-10, *Safety-related Motor Operated Valve Testing and Surveillance*, U.S. Nuclear Regulatory Commission, June 28, 1989; through supplement 7, January 24, 1996.

NRC Generic Letter 88-01, *NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping*, U.S. Nuclear Regulatory Commission, January 25, 1988.

NUREG-0313, Rev. 2, *Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping*, W. S. Hazelton and W. H. Koo, U.S. Nuclear Regulatory Commission, 1988.

## XI.M26 FIRE PROTECTION

### Program Description

For operating plants, the fire protection aging management program (AMP) includes a fire barrier inspection program and a diesel-driven fire pump inspection program. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, and periodic visual inspection and functional tests of fire rated doors to ensure that their operability is maintained. The diesel-driven fire pump inspection program requires that the pump be periodically tested to ensure that the fuel supply line can perform the intended function. The AMP also includes periodic inspection and testing of the halon/carbon dioxide (CO<sub>2</sub>) fire suppression system.

### Evaluation and Technical Basis

1. **Scope of Program:** For operating plants, the AMP manages the aging effects on the intended function of the penetration seals, fire barrier walls, ceilings, and floors, and all fire rated doors (automatic or manual) that perform a fire barrier function. It also manages the aging effects on the intended function of the fuel supply line. The AMP also includes management of the aging effects on the intended function of the halon/CO<sub>2</sub> fire suppression system.
2. **Preventive Actions:** For operating plants, the fire hazard analysis assesses the fire potential and fire hazard in all plant areas. It also specifies measures for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability for each fire area containing structures, systems, and components important to safety.
3. **Parameters Monitored/Inspected:** Visual inspection of approximately 10% of each type of penetration seal is performed during walkdowns carried out at least once every refueling outage. These inspections examine any sign of degradation such as cracking, seal separation from walls and components, separation of layers of material, rupture and puncture of seals, which are directly caused by increased hardness, and shrinkage of seal material due to weathering. Visual inspection of the fire barrier walls, ceilings, and floors examines any sign of degradation such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. Fire-rated doors are visually inspected on a plant-specific interval to verify the integrity of door surfaces and for clearances. The plant-specific inspection intervals are to be determined by engineering evaluation to detect degradation of the fire doors prior to the loss of intended function.

The diesel-driven fire pump is under observation during performance tests such as flow and discharge tests, sequential starting capability tests, and controller function tests for detection of any degradation of the fuel supply line.

The periodic visual inspection and function test is performed at least once every six months to examine the signs of degradation of the halon/CO<sub>2</sub> fire suppression system. Material conditions that may affect the performance of the system, such as corrosion, mechanical damage, or damage to dampers, are observed during these tests.

4. **Detection of Aging Effects:** Visual inspection of penetration seals detects cracking, seal separation from walls and components, and rupture and puncture of seals. Visual inspection by fire protection qualified inspectors of approximately 10% of each type of seal

in walkdowns is performed at least once every refueling cycle. If any sign of degradation is detected within that sample, the scope of the inspection is expanded to include additional seals. Visual inspection by fire protection qualified inspectors of the fire barrier walls, ceilings, and floors, performed in walkdowns at least once every refueling outage ensures timely detection of concrete cracking, spalling, and loss of material. Visual inspection by fire protection qualified inspectors detects any sign of degradation of the fire door such as wear and missing parts. Periodic visual inspection and function tests detect degradation of the fire doors before there is a loss of intended function.

Periodic tests performed at least once every refueling outage, such as flow and discharge tests, sequential starting capability tests, and controller function tests performed on diesel-driven fire pump ensure fuel supply line performance. The performance tests detect degradation of the fuel supply lines before the loss of the component intended function.

Visual inspections of the halon/CO<sub>2</sub> fire suppression system detect any sign of added degradation, such as corrosion, mechanical damage, or damage to dampers. The periodic function test and inspection performed at least once every six months detects degradation of the halon/CO<sub>2</sub> fire suppression system before the loss of the component intended function.

5. **Monitoring and Trending:** The aging effects of weathering on fire barrier penetration seals are detectable by visual inspection and, based on operating experience, visual inspections are performed at least once every refueling outage to detect any sign of degradation of fire barrier penetration seals prior to loss of the intended function.

Concrete cracking, spalling, and loss of material are detectable by visual inspection and, based on operating experience, visual inspection performed at least once every refueling outage detects any sign of degradation of the fire barrier walls, ceilings, and floors before there is a loss of the intended function. Based on operating experience, degraded integrity or clearances in the fire door are detectable by visual inspection performed on a plant-specific frequency. The visual inspections detect degradation of the fire doors prior to loss of the intended function.

The performance of the fire pump is monitored during the periodic test to detect any degradation in the fuel supply lines. Periodic testing provides data (e.g., pressure) for trending necessary.

The performance of the halon/CO<sub>2</sub> fire suppression system is monitored during the periodic test to detect any degradation in the system. These periodic tests provide data necessary for trending.

6. **Acceptance Criteria:** Inspection results are acceptable if there are no visual indications (outside those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or punctures of seals; no visual indications of concrete cracking, spalling and loss of material of fire barrier walls, ceilings, and floors; no visual indications of missing parts, holes, and wear and no deficiencies in the functional tests of fire doors. No corrosion is acceptable in the fuel supply line for the diesel-driven fire pump. Also, any signs of corrosion and mechanical damage of the halon/CO<sub>2</sub> fire suppression system are not acceptable.



7. **Corrective Actions:** For fire protection structures and components identified within scope that are subject to an AMR for license renewal, the applicant's 10 CFR Part 50, Appendix B, program is used for corrective actions, confirmation process, and administrative controls for aging management during the period of extended operation. This commitment is documented in the final safety analysis report (FSAR) supplement in accordance with 10 CFR 54.21(d). As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.
8. **Confirmation Process:** See Item 7, above.
9. **Administrative Controls:** See Item 7, above.
10. **Operating Experience:** Silicone foam fire barrier penetration seals have experienced splits, shrinkage, voids, lack of fill, and other failure modes (IN 88-56, IN 94-28, and IN 97-70). Degradation of electrical racing way fire barrier such as small holes, cracking, and unfilled seals are found on routine walkdown (IN 91-47 and GL 92-08). Fire doors have experienced wear of the hinges and handles.

#### References

- 10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.
- NRC Generic Letter 92-08, *Thermo-Lag 330-1 Fire Barrier*, U.S. Nuclear Regulatory Commission, December 17, 1992.
- NRC Information Notice 88-56, *Potential Problems with Silicone Foam Fire Barrier Penetration Seals*, U.S. Nuclear Regulatory Commission, August 14, 1988.
- NRC Information Notice 91-47, *Failure of Thermo-Lag Fire Barrier Material to Pass Fire Endurance Test*, U.S. Nuclear Regulatory Commission, August 6, 1991.
- NRC Information Notice 94-28, *Potential problems with Fire-Barrier Penetration Seals*, U.S. Nuclear Regulatory Commission, April 5, 1994.
- NRC Information Notice 97-70, *Potential problems with Fire Barrier Penetration Seals*, U.S. Nuclear Regulatory Commission, September 19, 1997.

## XI. M27 FIRE WATER SYSTEM

### Program Description

This aging management program (AMP) applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, water storage tanks, and aboveground and underground piping and components that are tested in accordance with the applicable National Fire Protection Association (NFPA) codes and standards. Such testing assures the minimum functionality of the systems. Also, these systems are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated.

A sample of sprinkler heads is to be inspected by using the guidance of NFPA 25 "Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (1998 Edition), Section 2-3.1.1, or NFPA 25 (2002 Edition), Section 5.3.1.1.1. This NFPA section states "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." It also contains guidance to perform this sampling every 10 years after the initial field service testing.

The fire protection system piping is to be subjected to required flow testing in accordance with guidance in NFPA 25 to verify design pressure or evaluated for wall thickness (e.g., non-intrusive volumetric testing or plant maintenance visual inspections) to ensure that aging effects are managed and that wall thickness is within acceptable limits. These inspections are performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation. The plant-specific inspection intervals are to be determined by engineering evaluation of the fire protection piping to ensure that degradation will be detected before the loss of intended function. The purpose of the full flow testing and wall thickness evaluations is to ensure that corrosion, MIC, or biofouling is managed such that the system function is maintained.

### Evaluation and Technical Basis

1. **Scope of Program:** The AMP focuses on managing loss of material due to corrosion, MIC, or biofouling of carbon steel and cast-iron components in fire protection systems exposed to water. Hose stations and standpipes are considered as piping in the AMP.
2. **Preventive Actions:** To ensure no significant corrosion, MIC, or biofouling has occurred in water-based fire protection systems, periodic flushing, system performance testing, and inspections may be conducted.
3. **Parameters Monitored/Inspected:** Loss of material due to corrosion and biofouling could reduce wall thickness of the fire protection piping system and result in system failure. Therefore, the parameters monitored are the system's ability to maintain pressure and internal system corrosion conditions. Periodic flow testing of the fire water system is performed using the guidelines of NFPA 25, or wall thickness evaluations may be performed to ensure that the system maintains its intended function.
4. **Detection of Aging Effects:** Fire protection system testing is performed to assure that the system functions by maintaining required operating pressures. Wall thickness evaluations of fire protection piping are performed on system components using non-

intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections are performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation. As an alternative to non-intrusive testing, the plant maintenance process may include a visual inspection of the internal surface of the fire protection piping upon each entry to the system for routine or corrective maintenance, as long as it can be demonstrated that inspections are performed (based on past maintenance history) on a representative number of locations on a reasonable basis. These inspections must be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the piping as it applies to the design flow of the fire protection system. If the environmental and material conditions that exist on the interior surface of the below grade fire protection piping are similar to the conditions that exist within the above grade fire protection piping, the results of the inspections of the above grade fire protection piping can be extrapolated to evaluate the condition of below grade fire protection piping. If not, additional inspection activities are needed to ensure that the intended function of below grade fire protection piping will be maintained consistent with the current licensing basis for the period of extended operation. Continuous system pressure monitoring, system flow testing, and wall thickness evaluations of piping are effective means to ensure that corrosion and biofouling are not occurring and the system's intended function is maintained.

General requirements of existing fire protection programs include testing and maintenance of fire detection and protection systems and surveillance procedures to ensure that fire detectors, as well as fire protection systems and components are operable.

Visual inspection of yard fire hydrants performed annually in accordance with NFPA 25 ensures timely detection of signs of degradation, such as corrosion. Fire hydrant hose hydrostatic tests, gasket inspections, and fire hydrant flow tests, performed annually, ensure that fire hydrants can perform their intended function and provide opportunities for degradation to be detected before a loss of intended function can occur.

Sprinkler heads are inspected before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

5. **Monitoring and Trending:** System discharge pressure is monitored continuously. Results of system performance testing are monitored and trended as specified by the associated plant commitments pertaining to NFPA codes and standards. Degradation identified by non-intrusive or internal inspection is evaluated.
6. **Acceptance Criteria:** The acceptance criteria are (a) the ability of a fire protection system to maintain required pressure, (b) no unacceptable signs of degradation observed during non-intrusive or visual assessment of internal system conditions, and (c) that no biofouling exists in the sprinkler systems that could cause corrosion in the sprinkler heads.
7. **Corrective Actions:** Repair and replacement actions are initiated as necessary. For fire water systems and components identified within scope that are subject to an AMR for license renewal, the applicant's 10 CFR Part 50, Appendix B, program is used for corrective actions, confirmation process, and administrative controls for aging management during the period of extended operation. As discussed in the appendix to

this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

8. **Confirmation Process:** See Item 7, above.
9. **Administrative Controls:** See Item 7, above.
10. **Operating Experience:** Water-based fire protection systems designed, inspected, tested and maintained in accordance with the NFPA minimum standards have demonstrated reliable performance.

#### References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NFPA 25: *Inspection, Testing and Maintenance of Water-Based Fire Protection Systems*, 1998 Edition.

NFPA 25: *Inspection, Testing and Maintenance of Water-Based Fire Protection Systems*, 2002 Edition.

## XI.M28 BURIED PIPING AND TANKS SURVEILLANCE

### Program Description

The program includes surveillance and preventive measures to mitigate corrosion by protecting the external surface of buried carbon steel piping and tanks. Surveillance and preventive measures are in accordance with standard industry practice, based on National Association of Corrosion Engineers (NACE) Standards RP-0285-95 and RP-0169-96, and include external coatings, wrappings, and cathodic protection systems.

### Evaluation and Technical Basis

1. **Scope of Program:** The program relies on preventive measures, such as coating, wrapping, and cathodic protection, and surveillance, based on NACE Standard RP-0285-95 and NACE Standard RP-0169-96, to manage the effects of corrosion on the intended function of buried tanks and piping, respectively.
2. **Preventive Actions:** In accordance with industry practice, underground piping and tanks are coated during installation with a protective coating system, such as coal tar enamel with a fiberglass wrap and a kraft paper outer wrap, a polyolefin tape coating, or a fusion bonded epoxy coating to protect the piping from contacting the aggressive soil environment. A cathodic protection system is used to mitigate corrosion where pinholes in the coating allow the piping or components to be in contact with the aggressive soil environment. The cathodic protection imposes a current from an anode onto the pipe or tank to stop corrosion from occurring at defects in the coating.
3. **Parameters Monitored/Inspected:** The effectiveness of the coatings and cathodic protection system, per standard industry practice, is determined by measuring coating conductance, by surveying pipe-to-soil potential, and by conducting bell hole examinations to visually examine the condition of the coating.
4. **Detection of Aging Effects:** Coatings and wrapping can be damaged during installation or while in service and the cathodic protection system is relied upon to avoid any corrosion at the damaged locations. Degradation of the coatings and wrapping during service will result in the requirement for more current from the cathodic protection rectifier in order to maintain the proper cathodic protect potentials. Any increase in current requirements is an indication of coating and wrapping degradation. A close interval pipe-to-soil potential survey can be used to locate the locations where degradation has occurred.
5. **Monitoring and Trending:** Monitoring the coating conductance versus time or the current requirement versus time provides an indication of the condition of the coating and cathodic protection system when compared to predetermined values.
6. **Acceptance Criteria:** In accordance with accepted industry practice, per NACE Standard RP-0285-95 and NACE Standard RP-0169-96, the assessment of the condition of the coating and cathodic protection system is to be conducted on an annual basis and compared to predetermined values.

7. **Corrective Actions:** The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.
8. **Confirmation Process:** See Item 7, above.
9. **Administrative Controls:** See Item 7, above.
10. **Operating Experience:** Corrosion pits from the outside diameter have been discovered in buried piping with far less than 60 years of operation. Buried pipe that is coated and cathodically protected is unaffected after 60 years of service. Accordingly, operating experience from application of the NACE standards on non-nuclear systems demonstrates the effectiveness of this program.

## References

- 10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.
- NACE Standard RP-0169-96, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*, 1996.
- NACE Standard RP-0285-95, *Corrosion Control of Underground Storage Tank Systems by Cathodic Protection*, Approved March 1985, revised February 1995.

## VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage

## Inspection Location Worksheets / Methods and Reasons for Component Selection

By: James C. Fitzpatrick

JCF 4/3/06

Reviewed: Thomas M. O'Connor

TMO 5/10/06

**FAC PROGRAM INSPECTION PLANNING:**

Piping components are selected for inspection during the Spring 2007 refueling outage (RFO26) are based on the following groupings and/or criteria:

Large Bore Piping

- LA: Components selected from measured or apparent wear found in previous inspection results.
- LB: Components ranked high for susceptibility from current CHECWORKS evaluation and /or identified as having the highest increases in flow velocities under EPU conditions.
- LC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.
- LD: Components selected to calibrate the CHECWORKS models.
- LE: Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. (through the Systems Engineering Group).
- LF: Engineering judgment / Other
- LG: Piping identified from EMPAC Work Orders (malfunctioning equipment, leaking valves, etc.)
- LH: Components "De-Scoped" (inspections deferred) from Previous Outages

Small Bore Piping

- SA: Susceptible piping locations (groups of components) contained in the Small Bore Piping data base which have not received an initial inspection.
- SB: Components selected from measured or apparent wear found in previous inspection results.
- SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.
- SD: Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. (through the Systems Engineering Group).
- SE: Engineering Judgment / Other.
- SG: Piping identified from EMPAC Work Orders (malfunctioning equipment, leaking valves, etc.)
- SH: Components "De-Scoped" (inspections deferred) from Previous Outages

Feedwater Heater Shells

No feedwater heater shell inspections will be performed during the 2007 RFO. All 10 of the feedwater heater shells have been replaced with FAC resistant materials.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LA: Large Bore Components selected (identified) from previous Inspection Results**

From the 1996 through 2005 Refueling Outage Inspection Reports, references (2) to (8): Large Bore Piping components were identified as requiring future monitoring. The following components have either yet to be inspected as recommended, or the recommended inspection is in a future outage.

Inspect. No.	Loc. SK.	Component ID	Notes /Comments / Conclusions
96-18 96-19	001	FD13EL05 FD13SP06	1996 Report: calculated time to Tmin is 11.5 & 12 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. <b>UT inspect elbow and downstream pipe in 2008</b>
96-36	002	FD02SP05	1996 Report: calculated time to Tmin is 9.5 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. <b>UT inspect elbow and downstream pipe in 2007</b>
96-37	005	FD07SP01	1996 Report: calculated time to Tmin is 9.6 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. DS elbow shows significant margin RSL= 47 cycles from 1996. EPU flow will increase velocity ~22%. <b>UT inspect upstream pipe FD07SP01DS, elbow FD07EL02, and downstream pipe FD07SP02US in 2007 (repeat the 1996 inspections)</b>
96-39	005	FD07SP02US	1996 Report: calculated time to Tmin is 10.5 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. <b>UT inspect upstream pipe FD07SP01DS, elbow FD07EL02, and downstream pipe FD07SP02US in 2007 (repeat the 1996 inspections)</b>
98-05 98-07	005	FD07EL06 FD07EL07	1998 Report: calculated time to Tmin is 7.5 & 6.7 cycles based on a single measurement. The 2007 RFO is 6 cycles since the inspection. Review of 1998 data for FD07EL06, FD07SP07, and FD07EL07 shows recommendations were made based on wear rates conservatively calculated from single low point measurements at weld counterbores. Significant margins exist on body of pipe and elbows. Defer this inspection to RFO 27 in 2008. At that time components will have ~1.7 cycles of operation under increased EPU flows. <b>UT inspect elbow FD07EL07 and downstream pipe FD07SP08 in 2008</b>
99-13	011	FD08EL04 FD08SP04	1999 Report: calculated time to Tmin is 7.9 & 12.5 cycles based on a single UT inspection. The 2007 RFO is 5 cycles since the inspection. Review of 1999 data for FD08EL04, & FD08SP04, shows recommendations were made based on wear rates conservatively calculated from single low point measurements at weld counterbores. Significant margins exist on body of pipe and elbows. Defer this inspection to RFO 27 in 2008. At that time components will have ~1.7 cycles of operation under increased EPU flows. <b>UT inspect elbow and downstream pipe in 2008</b>
99-16	011	FD08SP05	1999 Report: calculated time to Tmin is 6.1 cycles based on a single measurement. The 2007 RFO is 5 cycles since the inspection. <b>UT inspect pipe in 2007.</b>
02-08 02-09	016	FD18EL01 FD18SP02US	2002 Report: calculated time to Tmin is 7.92 cycles based on a single UT inspection. The 2007 RFO is 3 cycles since the inspection. Review of 2002 data for FD18EL01, & FD18SP02US, shows recommendations were made based on wear rates conservatively calculated from single low point measurements at weld counterbores. Significant margins exist on body of pipe and elbows. Defer this inspection to RFO 27 in 2008. At that time components will have ~1.7 cycles of operation under increased EPU flows. <b>Re-inspect elbow and downstream pipe in 2008 (4 cycles from 2002).</b>



**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage  
Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LA: Large Bore Components selected (identified) from previous Inspection Results –continued**

Inspect. No.	Loc. SK.	Component ID	Notes /Comments / Conclusions
04-03	001	FD01TE05	2004 recommendation to inspect tee in 2008 based on the default wear rate of 0.005 inch/cycle. Flow on B FDW pump increases from ½ usage/standby for CLTP to full time usage and 80% of CLTP flow for EPU. <b>Re-inspect upstream elbow and tee in 2008.</b>
04-06	002	FD02RD01	2004 recommendation to re-inspect in 2011 based on the default wear rate of 0.005 inch/cycle. Flow on B FDW pump increases from ½ usage/standby for CLTP to full time usage and 80% of CLTP flow for EPU. <b>Re-inspect reducer with downstream elbow and tee in 2008.</b>
04-08	001	FD02TE01	2004 recommendation to inspect tee in 2007 based on the default wear rate of 0.005 inch/cycle. Actual point to point measurements from 1999 to 2004 indicate no wear. Given EPU operation, re-inspect with upstream elbow and reducer in 2008.
04-09	001	FD03SP01	2004 recommendation to inspect pipe section in 2011 based on a single inspection and the default wear rate of 0.005 inch/cycle. <b>Re-inspect in 2011.</b>
04-10	001	FD07SP02DS	2004 recommendation to inspect pipe section in 2008 based on a single inspection. <b>Re-inspect with downstream elbow in 2008.</b>
04-13	001	FD14EL03	2004 recommendation to inspect Row 13 pup piece to DS valve in 2008 is based on a single UT inspection. <b>Re-inspect in 2008.</b>
04-23	001	MSD9TE01 to MSD9TE08	2004 recommendation to inspect pipe section in 2010 due to localized wear directly under 2 small bore lines entering flow at top of pipe. <b>Re-inspect in 2010.</b>
04-23	001	MSD9EL05	2004 recommendation to inspect pipe section in 2010 base on a single inspection. <b>Re-inspect in 2010.</b>
05-12	011	FD08RD03	2005 Recommendation to inspect this component and downstream straight pipe in RFO28 ~Spring 2010 due to increases flow velocity from EPU. <b>Re-inspect FD08RD03 and FD08SP02 in 2010.</b>
05-03 05-04 05-05	017	FD04RD01 FD04TE01 Cond Nzl 32A	During normal operation there is no flow in these lines. No current leakage is indicated since the upstream FCV repairs were performed during RFO24. This piping was inspected in RFO 25 to determine if past leakage has caused wear since the last inspections and to insure the condition of the piping for Extend Power Uprate conditions. 2005 Recommendation to use the Thermal Performance Monitoring (TPM) system to determine if flow is occurring in this pipe during normal operation. The Thermal Performance Monitoring (TPM) system will be used as a trigger to determine if future inspections are required. The monthly TPM report will be monitored by the FAC program Engineer.
05-06 05-07 05-08	018	FD05RD01 FD05TE01 Cond Nzl 32B	
05-09 05-10 05-11	019	FD06RD01 FD06TE01 Cond Nzl 32C	

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LA: Large Bore Components selected(identified) from previous Inspection Results -continued**

**Turbine Cross-around Piping:**

Summary of previous Internal Visual UT & Repair History:

Line	Mat.	Year Replaced	Internal Visual =V		Internal Thickness =UT		Repairs Performed =R					
			RFO16 S1992	RFO17 F1993	RFO18 S1995	RFO19 F1996	RFO20 S1998	RFO21 F1999	RFO22 S2001	RFO23 F2002	RFO24 S2004	RFO25 F2005
36"-A	GE**	1983		V	V	V	V				V	V
36"-B	GE**	1981	V	V	V	V	V	V			V	
36"-C	GE**	1981	V	V	V		V				V	V
36"-D	GE**	1983		V	V		V				V	
30"-A	P-22*	1985	V		V		V					
30"-B	C.S.	Original	V/UT/ R	V/UT/ R	V/UT/ R	V/UT	V	V		V		V
30"-C	P-22*	1993	V/UT/ R								V	
30"-D	P-22*	1985			V						V	

\*\* 36" straight pipe sections replaced with GE B50A242E, elbows on the B & C lines are original GE specification D50A67D; elbows on A & D lines are D50A67E (Tnom = 0.625 inch).

\* 30" A,B,C replaced with A691 CL22 (2-1/4Cr), Fittings A234 WP22. (Tnom. = 0.625 inch)

30" B remains GE B50A242D, fittings and GE D50A67D carbon steel (Tnom = 0.50 inch).

**2007 RFO:**

The last remaining carbon steel 30 inch, (30" B, upper east), line was inspected to confirm its condition prior to power uprate flows. Increased EPU flows and an expected drop in Moisture Separator efficiency will most likely result in resumption of FAC in this line. Results of the planned MS efficiency tests at EPU flows will quantify any drop in steam quality in these lines and provide some basis for estimating the increase in susceptibility to FAC damage. If the proposed testing at EPU flows shows no loss in MS efficiency, this inspection could be deferred until RFO27. For planning purposes:

Perform a complete visual inspection of 30" B line in RFO 26 will be planned to insure wall loss due to FAC has not resumed under EPU flow conditions. This will require coordination with planned LP turbine work scheduled for RFO26.

**VY Piping FAC Inspection Program PP 7028 - 2004 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LB: Components ranked high for susceptibility from current CHECWORKS evaluation and /or identified as having the highest increases in flow velocities under EPU conditions.**

The current CHECWORKS wear rate calculations contain inspection data up to the 1999 RFO and wear rate predictions are current to the 2001 RFO. The 2001 and 2002 RFO inspection data has been entered into the CHECWORKS database. CHECWORKS predictive models for Piping FAC Inspection Program are updated as required per Appendix D of PP 7028. This is documented in CR-2005-2239. This is a procedure compliance issue. There are no operability concerns. Actual measured wear rates from 2001, 2002, 2004, and 2005 inspections are an order of magnitude less than the CHECWORKS predicted wear rates. If the 2002, 2004, and 2005 inspection data were incorporated into the models the CHECWORKS predicted wear rates would be reduced. Use of the un-updated CHECWORKS model results as a basis for inspection planning is conservative in that scoping decisions documented in the Inspection Location Worksheets were based on the CHECWORKS Predicted wear rates significantly greater than actual measure wear.

The updated wear rate calculations are in progress, and won't be complete in time to support the outage schedule milestone date for issuing the inspection scope for the 2007 outage. Based on a review of the 2001 thru 2005 RFO inspection data for components on the Feedwater, Condensate, and Heater Drain Systems, the CHECWORKS models still appear to over-predict actual wear. The existing model results will be used to rank components for inspection in 2007. The component selections will be reviewed upon completion of the CHECWORKS model updates.

**Feedwater System**

Listed below are components which meet the following criteria:

- a) Negative time to Tmin from the predictive CHECWORKS runs which include inspection data up to the 1999 RFO.
- b) No inspections have been performed on these components or the corresponding components in a parallel train since the 1999 RFO.

Component ID	Location Sketch	Location	Notes
FD07EL05	005	TB FPR Elev. 241	Comparable component on other train FD08EL04 was inspected in 1999 and results indicate minimal wear. After updating the Checworks model with newer data, assess need for inspections in 2008 RFO. (Note upstream components FD07RD02 and FD07SP03 will be inspected in 2007)
FD07TE01 FD07EL11	006	T.B Heater Bay Elevs 228 & 248	Components on other train were inspected in 1998. Results indicate minimal wear. Inspect FD07TE01, FD07EL01, and FD07SP11 in 2007 RFO.
FD07EL12	006	T.B Heater Bay Elev. 248	Feedwater heater replacement occurred in 2004 RFO. Informal visual inspections of internals and cut pipe profile indicated a stable red oxide and no distinguishable wear pattern. After updating the Checworks model with newer data, assess need for inspection
FD08TE01 FD08EL07	012	T.B Heater Bay Elevs 228 & 248	Intermediate components FD08EL06 & FD08SP06 were inspected in 1998. Results indicate minimal wear. After updating Checworks model with newer data, assess need for inspecting components.
FD08EL08	012	T.B Heater Bay Elev. 248	Feedwater heater replacement occurred in 2004 RFO. Informal visual inspections of internals and cut pipe profile indicated a stable red oxide and no distinguishable wear pattern.
FD15EL08	013	RX Steam Tunnel El. 266	Internal visual of elbow performed in 1996 during check valve replacement, no indication of wall loss at that time. Corresponding component on line 16" - FDW-14 was inspected in RFO24. After updating Checworks model with inspection data, assess need for inspection in 2008 RFO.

VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage  
Inspection Location Worksheets / Methods and Reasons for Component Selection

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LB: Components ranked high for susceptibility from current CHECWORKS evaluation and/or identified as having the highest increases in flow velocities under EPU conditions - continued

Condensate System

Only one component was identified as having a negative time to T<sub>min</sub>. This was CD30TE02DS, the downstream side of a 24x24x20 tee on the condensate header in the feed pump room. The CHECWORKS prediction for the downstream side of the tee has a small negative hrs relative to the remainder of the components in the system and relative to the upstream side of the same tee. Other tees on the same header have been previously inspected and show no significant wear. The CHECWORKS model includes UT data up to the 1999 RFO. The inspections on this system performed in 2001, 2004, and 2005 indicate minimal wear.

Components CD30TE02 and CD30SP04 were inspected in 2004. Additional components downstream of condensate flow elements FE-102-2A and FE-102-2B on inlets to FDW pumps A & B were performed in 2005 with no significant wear observed. This inspection data will be input to CHECWORKS to better calibrate the model.

Moisture Separator Drains & Heater Drain System

No components identified as having negative times to T<sub>min</sub>. No components were selected for inspection in 2001, 2002, or 2004 based on high susceptibility. However, operation under HWC changes dissolved oxygen in the system. A separate CHECWORKS evaluation was performed to assess the differences in projected wear rates between Normal water chemistry and Hydrogen water chemistry. Selected HD components were inspected in 2002 to obtain pre-HWC operation wall thickness data. See Section LD below.

Extraction Steam System

Three components on this system with negative time to code min. wall: The piping is Chrome-Moly. ES4ATE01 & ES4ATE02, 30inch diameter tees inside the condenser have negative prediction (-3426Hrs.) for time to min wall. The negative times to t<sub>min</sub> may be conservative based on the modeling techniques used. Refinement of the model of this system is in progress. The negative time to t<sub>min</sub> is most likely a function of lack of inspection data vs. actual wear. Due to external lagging on this piping and the location inside the condenser, no components are selected for external UT inspection in 2007 based on high susceptibility.

Note the short section of straight pipe on line 12"-ES-1A at the connection to the 36 inch A cross around is assumed to be A106 Gr. B carbon steel is not modeled in CHECWORKS. This component was inspected in 2004 by external UT and an internal visual inspection from the 36" cross around line was performed in both 2004 and 2005.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
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**LC: Large Bore Components Identified by Industry Events/Experience.**

Review of FAC related Large Bore Operating Experience (OE) and/or piping failures reported since April 2003

Date	Plant - Type	Description & Recommended Actions at VY
5/9/01	Grand Gulf - BWR	Pin Hole Leak in 4 inch carbon steel elbow in RHR min flow line. System has low use at VY (<2% of time). Perry also found thinning at elbow per C.Burton at CHUG meeting.) A review of VY drawings VYI-RHR-Part 14 Sht.1/1 and VYI-RHR Part 15 Sht.1/1 show elbows downstream of restriction orifices. Previous VY inspections downstream of orifices on HPCI and CS systems found no problems. Keep this OE listed for future consideration if similar industry events are identified.
1/15/02 CHUG Meeting	Surry 1-PWR	Leak in 8 inch Condenser drain header for 3 <sup>rd</sup> /4" pi. FDW Heater vents. Also thinning in Gland Steam Piping inside the condenser and the 12" Condenser Drain header from MS Drain trap lines. The only large bore drain collector at VY is the 8 inch diameter low point drain header, line 8"MSD-9. This line is now part of the AST ALT boundary. Inspections of selected components on this line were performed during RFO24 with recommendations for repeat inspections in 2010 (Section LB above). Given this line is part of the ALT Boundary, inspect approx. 2 ft. long section at condenser wall during RFO26 (2007) MSD9SP07 at condenser nozzle 87 (Location Sketch 097)
6/26/03	Wolf Creek - PWR	OE16181: Leak in Main Feedwater Thermowell. The Thermowell is unused and was sealed with a pipe plug. Once the integrity of the plug was determined by RT, the main concern was potential for internal FME from the degraded Thermowell to affect downstream control valves. PWR feedwater piping more susceptible to FAC than BWR piping due to low DO. Keep this OE listed for future consideration if similar industry events are identified.
9/24/03	South Texas Project - PWR	OE17378: Pitting & internal wear found on discharge piping of Condensate Polishing System. Pipe is carbon steel, low water temperature (90 to 130F), neutral pH, and velocity of 12.2 Ft./sec Tortuous flow path and control valves, wear may be impingement. PWR system Low dissolved oxygen. Equivalent system at VY is Condensate Demineralizer System which is low temp and screens per NSAC-202L as not susceptible to FAC based on temperature. No OE on BWR Condemin systems.
10/10/03	Browns Ferry 3 -BWR	6/04 CHUG Meeting PER: Failure of No.2 Extraction Steam bellows inside condenser caused collateral damage in No.3, No.4A, & No.5B east bellows. In service for only 2-1/2 cycles. Failure due to welds/weld flaws in bellows. Additional erosion found in the carbon steel Extraction Steam lines inside the condenser was found during the unplanned mid-cycle outage for bellows repairs. At VY, the Extraction Steam piping inside condenser is Cr-Mo. The bellows were replaced in 1995. The System Engineer performed limited bellows inspections in RFO25. No new actions with respect to FAC for this OE.
10/17/03	Duane Arnold -BWR	OE17300: Through wall leak on 8 inch pipe between 6A feedwater heater and condenser. The pipe was chrome-moly. Temporary pipe configuration installed prior to replacing feedwater heater for power uprate. Cause of leak was droplet impingement erosion from use of bypass control valve. No actions required for VY. However, it should be noted that chrome-moly pipe is not immune to droplet impingement erosion.
10/31/03	Clinton -BWR	OE17412 / OE18478: Through-wall leaks in 2A/B heater vent lines to the condenser (larger bore lines assumed given description of backing rings in piping). Apparent cause attributed to steam jet impingement from wet steam. Equivalent line at VY is common 4 inch feedwater heater vent line for No.4 FDW heaters. AT VY this line is included in the SSB database since it connects to (2) 2-1/2" lines. Inspect this line at the condenser in RFO26 in 2007 [Inspection No.07-SB09]

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
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**LC: Large Bore Components Identified by Industry Events/Experience - continued.**

Date	Plant - Type	Description & Recommended Actions at VY
11/07/03	Braidwood-2-PWR	OE17454: Wall thinning found on FDW pump discharge nozzles and extending into downstream pipes on all 3 FDW pumps. Material has high chromium content. PWR feedwater system chemistry has low D.O. therefore more susceptible to wall loss due to single phase FAC than BWR feedwater piping. At VY all three feedwater pump discharge nozzles and downstream piping have multiple inspection data. No further actions are anticipated from this OE.
11/19/03	Hope Creek - BWR	OE17700: Pinhole leak and wall thinning in 8" in carbon steel Extraction Steam supply line to Steam Seal Evaporator. Location of wear is downstream of pressure safety valves. Apparent Cause of leak & wear is due to liquid droplet impingement due to high flows from failure of pressure safety relief valves. No equivalent configuration at VY.
1/24/04	LaSalle 1 - BWR	OE17199 / OE18381: Through-wall holes in extraction steam piping inside condenser. Location of holes at inlet nozzles to No.2 FDW heaters located in the neck of the condensers (2 <sup>nd</sup> lowest stage). All 12 nozzles are C.S. with A335-P11 upstream piping. VY has only the No. 5 FDW heaters in the neck of the condenser. The No. 5 FDW heaters were replaced with Chromo-moly shells and ES piping nozzles. ES piping is A335-P11 or equivalent which is FAC resistant. No further actions are anticipated from this OE.
2/17/04	Peach Bottom 2 - BWR	OE18637: On line leak in 10 inch main steam drain line header to the condenser. Hole was located directly below the connection of 1" main steam lead drain. The header was replaced with 1-1/4 Chrome material approx. 5 years before the leak. Also, R.O.s in steam drains were modified. The cause was attributed to steam impingement. Additional information to follow after next RFO. The only large bore drain collectors at VY are the 8 inch diameter low point drain header, line 8"MSD-9, and line 3"-MSD-4 near the condenser. Flow is through steam traps and LCVs vs. a continuous flow through a restriction orifice. These lines are now part of the AST ALT boundary. For MSD-9, inspection of the entire bottom of this header under the MSD lines was performed during RFO24 with recommendations for repeat inspections in 2010. Inspect 8"-MSD-9 at the Condenser in RFO26 (2007). For line 3"-MSD-4, see Small Bore OE in section SC below.
3/17/04	Farley 2 - PWR	OE18059: Nameplate Screws Holes Found Extended Into Flow Nozzle Pipe. 16 in. Sch.80, A106 Gr.C. Evaluated as a flaw and found acceptable. Only a concern if FAC wear is occurring in the pipe at the location of the nameplate. VY inspections to date for FDW and Condensate flow elements show no wear in pipe. No further actions for this OE.
3/27/04	Perry -BWR	6/04 CHUG PER: Through wall leak in a 12" diameter drain header (Main Steam, Reheat Steam, Extraction Steam, and Misc Drains collector) connecting to the condenser. The only large bore drain collectors at VY are the 8 inch diameter low point drain header, line 8"MSD-9, and line 3"-MSD-4 near the condenser. Flow is through steam traps and LCVs vs. a continuous flow through a restriction orifice. These lines are now part of the AST ALT boundary. For MSD-9, inspection of the entire bottom of this header under the MSD lines was performed during RFO24 with recommendations for repeat inspections in 2010. Inspect 8"-MSD-9 at the Condenser in RFO26 (2007). For line 3"-MSD-4 See Small Bore OE in section SC below.
7/05/04	Ohi-1 -PWR (Japan)	OE19492: OE describes wall thinning in PWR feedwater components between the feedwater isolation valves and the steam generators. No leaks, wall thinning was found through planned UT inspections. Components will be replaced with the same materials and additional inspections (increased frequency) will be performed. PWR feedwater piping more susceptible to FAC than BWR piping due to low DO. VY inspects final feedwater piping components. No wear found to date.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LC: Large Bore Components Identified by Industry Events/Experience - continued.**

Date	Plant - Type	Description & Recommended Actions at VY
7/30/04	Darlington Unit 4 - PHWR	INPO Event No.934-040730-1. Leak in 10 inch diameter Sch.50, HP Drains manifold. Material is low chrome-moly (2.25/1) alloy carbon steel. Darlington plans to increase inspection scope for HP Drains manifold piping. Cause of leaks attributed to liquid impingement. [ See 2/17/04 Peach Bottom 2 OE and 3/27/04 Perry OE evaluation of for VY above. Also, note that this OE demonstrates that Cr-Mo P22 material may not be the ultimate solution if liquid impingement is occurring. ]
8/9/04	Mihama 3 - PWR	OE19368/OE18895: Rupture of Condensate line downstream of restriction orifice. PWR system highly susceptible to single phase FAC due to low DO. Similar region of system as 1986 Surry event (5 fatalities). Based on info gathered by INPO/CHUG/FACnet the location was omitted from previous inspections due to clerical error, once discovered management missed opportunity to inspect and deferred inspection until 9/04. Too late. Lesson: make sure all highly susceptible locations get inspected. PWR Condensate/feedwater piping is much more susceptible to single phase FAC than BWR with O2 injection. A review of previous inspections DS of Flow Elements at VY shows: Condensate piping at and downstream of FE-102-2A & -2B was inspected in RFO25(2005) and piping at and downstream of FE-102-2C was inspected in RFO22(2001). Also feedwater piping downstream of FE-6-11A was inspected in RFO23(2002). See section LF below for discussion of Flow Elements in lower temperature Condensate piping.
8/10/04	Sequoyah 2 - PWR	OE19074: Leak in Heater Drain Tank Recirculation line downstream of the recirc. nozzle of the automatic recirculation valve. Suspected leakage by Normally Closed Valve. No similar configuration at VY.
8/26/04	Palo Verde 3 - PWR	OE20386: Through wall leak found on a 10 inch flashing tee cap on the LP feedwater heater drains. Problems with inspection of flashing tees in program. Only 14 out of 153 susceptible locations have UT data at Palo Verde 1,2,3. At VY there are 4 flashing tees D.S. of LCV-103-23A to -23D on the Moisture Separator Drain system at VY. These along with the blind flanges were replaced with Cr-Mo in 1992. The only other flashing tees at VY are located on the FWD pump min flow lines at the condenser. These have welded pipe caps. Inspection of all 3 lines 6"FDW-4, 6"FDW-5, and 6"FDW-6 performed in RFO25. No other actions for this OE.
9/18/04	Catawba 2 - PWR	OE19350: Wall thinning found four different areas on FDW piping. Two areas are not considered specific to Catawba: 1)Area where main feedwater bypass reg valves reenters the feedwater header and 2) downstream of the main feedwater reg valves. PWR feedwater system chemistry has low D.O. therefore more susceptible to wall loss due to single phase FAC than BWR feedwater piping. At VY area 1) does not exist (bypass lines dump to the condenser) 2) Inspections have been performed upstream and downstream of both main feed reg. valves. Inspections downstream of FCV-12B (FD08RD03 & FD03SP02) were performed in RFO25. Inspections downstream of FCV-12A planned for RFO26 given the increased velocities under EPU. No further actions are anticipated from this OE.
9/24/04	Palisades - PWR	OE19494: Wear found in carbon steel 12" Sch 40, Extraction Steam line downstream of bleeder trip valve. Wear found through FAC inspections. No through wall leak. This OE identifies potential for FAC damage in ES piping and problems with partial line (selected component) replacements. ES piping at VY is low alloy A335-P-11 Cr.Mo piping which is FAC resistant. No further actions for this OE

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

LC: Large Bore Components Identified by Industry Events/Experience - continued.

Date	Plant - Type	Description & Recommended Actions at VY
10/12/04	Prairie Island 1 - PWR	OE19365: Pipe Failure Internal to the Main Condenser Found During Outage Inspection. Failure in 14 x 8 reducing elbow and wall thinning in 8 inch pipe on line connecting hester drain tank to condenser. Failure discovered during routine condenser inspections before tube damage had occurred. VY performs internal condenser walkdowns each RFO with additional inspections during equipment maintenance. At VY piping attached to the condenser either has impingement plates to protect the tubes or spargers internal to the condenser to disburse flow. Extraction steam piping inside the condenser is Cr-Mo. Material. Visual inspection of the condenser steam space will be performed by System Engineering. No new inspections will be performed under the FAC Program for this OE.
11/3/04 (Note Follow-up present at 8/05 CHUG Meeting)	Duane Arnold - BWR	OE19701: Wall thinning downstream of Torus Cooling Test Return Header Isolation Valve. Apparent cause was cavitation erosion due to throttling in valve during HPCI & RCIC testing. At VY, the equivalent valves are V10-34A & 34B. The degree of cavitation present is dependent of the system design and may vary from plant to plant. Previous UT inspections at VY were performed on valve bodies and downstream reducers in early 90s. No significant wear was found. <b>Consider inspection of downstream piping in RFO27 if additional OE warrants it.</b>
2/17/05	Clinton - BWR	OE20246 and CHUG PER 1/06: Through wall leaks found in 12", 20", and 30" Extraction Steam Piping inside the condenser. These lines were not in the FAC program according to the Heat Balance they carry superheated steam. Equivalent piping at VY is in the FAC program and is Cr-Mo, A335 P-11
2/26/05	Calvert Cliffs 1 - PWR	OE20127: Through wall leak in 6 inch steam vent header from MSR drain tank to hot reheat header. Location of leak was at the end of elbow which had a backing ring. Leak location was at the backing ring. At VY, there are no backing rings in piping systems containing primary steam/water. Also, there are No MSRs at VY.
5/23/05	Vogtle Unit 2 -PWR	OE20793: Extraction Steam expansion bellows failure inside condenser caused collateral damage to feedwater heater shroud and condenser tubes. Not FAC. No further actions require for this OE.
6/05 CHUG Meeting	TEPCO Fukushima Dai-1 (2F-1) - BWR	Wall thinning downstream of a restriction orifice in the CRD pump supply line from Condensate System. Pipe Size 100A (approx. 4.5 inch O.D.). Location is DS of Control valve and restriction orifice on supply line to CRD pumps from the condensate system. VY has a similar configuration but without the Restriction Orifice. This line screens out of the VY FAC Susceptibility Evaluation based on low temperature. Comparison with VY: 1. Condensate supply is upstream of the oxygen injection point, same at VY. 2. MOV is a globe valve the same size as pipe. The valve is operated at 8% open to control flow with a restriction orifice just downstream of the valve. VY has a smaller size control valve than the main line. A 1-1/2" control valve (LCV-102-1A-3) with expanders from 1-1/2" to 2-1/2" then to the 4" diameter line with no restriction orifice. 3. Supply line is downstream of low pressure condensate pump. At VY supply is directly from hotwell. This results in a higher DP across the MOV & RO at TEPCO than across the LCV at VY. TEPCO has higher potential for cavitation and/or flashing due to the higher DP.  At VY, UT measurements on the valve body were performed 1992, but no measurements on the downstream piping. TEPCO root cause was FAC with <u>cavitation contributing at the RO</u> . Given there is no RO at VY and the LCV is operated at 60% open. The potential for a similar situation at VY is significantly less. <b>Scope out possible inspection locations on piping down stream of LCV-102-1A-3 during RFO26 in 2007.</b>
6/05 CHUG Meeting PER	Wolf Creek - PWR	Eroded elbow found in 12 inch LP feedwater heater drain line inside condenser. Erosion was external to pipe from main steam dump to condenser. No equivalent piping at VY. At VY only the No.5 FDW Htrs. are in the neck of the condenser. Heater drain piping is external to the condenser. The extraction steam piping inside the condenser has external lagging for protection and thermal efficiency.



**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage  
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**LC: Large Bore Components Identified by Industry Events/Experience - continued**

Date	Plant - Type	Description & Recommended Actions at VY
6/05 CHUG Meeting	Hatch Units 1 and 2 - BWR	Pinhole leaks in 3 inch line between Steam Packing Exhauster Drain Tank and Condenser in both units. The leak locations were at the first elbow downstream of the tank level control valves. The equivalent piping at VY is 6"C-44 at condenser nozzle 63. This line screens out of the VY FAC Susceptibility Evaluation based on low temperature. VY has two LCVs in parallel vs. the single valve on each of the Hatch units. Given that a leak in this line would affect condenser vacuum and challenge plant availability, inspect locations downstream of valves LCV-102-8-1 and LCV-102-8-2 in RFO26 (2007)
6/22/05	Callaway - PWR	OE19965: Failure of the carbon steel body section of an internal pipe flow element manufactured by Badger Meter blocked flow in a Heater Drain tank Pump discharge line. A separate evaluation of this OE was performed for VY. 3 Flow elements in the Condensate System; FE-102-2A to -2C have been identified as the same construction. UT inspections of piping US, the pipe at the flow element, and DS of each of the flow elements shows no wear is occurring. This is not a pressure boundary issue. An ER will be generated to develop the best scheme for inspection and evaluation of the internal portions of the pipe flow elements.
6/23/05	Palo Verde Unit 1 PWR	1/06 CHUG PER: Leak on 8"x 12" expander downstream of level control valve on MSR Drain tank to Heater Drain tank. No MSR or heater drain tank at VY. This is high pressure piping. The closest components would be the Moisture Separator Drain Piping downstream of LCV-103-24A to 24D. This piping is A335 P-22 material. Other components would be piping downstream of Heater Drain System LCV-103-1A-1/1B-1, LCV-103-2A-1/2B-1, and LCV-103-3A-1/3B-1. Piping downstream of these valves is either chrome moly or stainless steel. No new actions with respect to FAC for this OE.
8/16/05	Dresden 3 - BWR	OE21421/OE21968 Loss of Main Condenser vacuum due to air in leakage and a degraded SJAE train. Age related degradation of the 2 <sup>nd</sup> stage steam jets at Dresden. VY replaced the SJAE nozzles in 1993 (JO 92-0140). However, US & DS piping is original. ER 06-1190 was written to evaluate SJAE replacement including the need for additional FAC Inspections of the piping. With respect to the vent line internal to the condenser at Dresden which experienced external wear due to steam erosion, the equivalent section of piping at VY is stainless steel. The need to establish PMs for AE lines in the condenser will be addressed in the response to ER 06-1190.
9/26/05	Hatch Unit 1 - BWR	OE21591: Through wall leak in a Fisher control valve body. MSR Reheater 2 <sup>nd</sup> Stage High Level Dump. Hole in the 1 inch thick valve body was attributed to leakage past the seat. The valve had been modified for power uprate. The trim was changed to avoid installing a larger actuator on the valve. This OE was forwarded to the Systems/TPM Engineer. The TPM system will be used to identify leakage by normally closed valves to the condenser.. The monthly TPM report will be monitored by the FAC program Engineer.
1/06 CHUG Meeting	Surry - PWR	Hidden spool piece discovered. Plant replacement practices in two separate local material replacements (Cr-Mo) on a 6 inch line at the upstream elbow and the downstream elbow resulted in a carbon steel spool piece remaining in the line. This situation highlights importance of configuration control, potential hazards of partial replacement strategy, and the need for alloy sampling.
1/06 CHUG Meeting	Susquehanna Unit 2 - BWR	Through wall damage found in 3" and 4" diameter FW heater vent piping and associated condenser nozzles during pipe replacement activities. Caused increased condenser in-leakage. Heater Vent Piping at VY is monitored for FAC in Small Bore Program.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage  
Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LD: Large Bore Components Selected to Calibrate CHECWORKS**

The CHECWORKS wear rate calculations have been upgraded to include the '96, '98, & '99 RFO inspection data. The 2001 and 2002 inspection data has been loaded however wear rate analyses have not been completed at this time.

Condensate:

In 2001 components on the higher temperature end of the Condensate System were inspected to calibrate the CHECWORKS models. The inspection data indicate minimal wear and should reinforce the assessment of low wear in the Condensate System. Additional inspections were performed on lines CD-30, CD-31 and CD-32 in 2004 and 2005. There is no inspection data on line 20"-C-28 between the E-4-1B and E-3-1B feedwater heaters for CHECWORKS calibration. Given the increase in operating temperature & flows for EPU, inspect components CD28EL04 & CD28SP03US in RFO26 (2007).

Heater Drains/ Moisture Separator Drains:

Prior to the 2002 RFO there was limited inspection data for the Heater Drain system. The current CHECWORKS models (Pass 1 and some Pass 2) indicate low wear rates. During 2002 a number of new inspections were performed on the carbon steel piping upstream of the level control valves (LCV) to obtain a baseline prior to operation on hydrogen water chemistry. The 2002 inspection data indicate significant margin for future wear in the components inspected.

Piping downstream of the level control valves (LCV) for the feedwater heaters is FAC resistant material, except for inlet to No.5 Feedwater heaters. The carbon steel piping downstream of the normal flow LCV-4B-1 will be inspected in RFO26. Additional components on lines which do not already have inspection data will be inspected in RFO26. (2007) are listed below.

Inspection	Component ID	Loc. Sketch	Location	Previous Inspections	Reasons / Comments / Notes
2007-27	HD1AEL06	043	T.B. Htr. Bay Elev. 235.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-28	HD1ASP08	043	" " "	NO	
2007-29	HD3BTE01	051	T.B. Htr. Bay Elev. 239.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-30	HD3BEL02	051	" " "	NO	
2007-31	HD3BSP05US	051	" " "	NO	
2007-32	HD5ATE01	045	T.B. Htr. Bay Elev. 239.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-33	HD5ASP06	045	" " "	NO	
2007-31	HD3BSP05US	045	" " "	NO	
2007-32	HD25RD02	053	T.B. Htr. Bay Elev. 253	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-33	HD5ASP02	053	Inlet to E5-1-B	NO	
2007-34	HD12TE01	057	T.B. Htr. Bay Elev. 229.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-35	HD12SP01	057	MS-1-1A drain	NO	
2007-36	HD12EL06	058	T.B. Htr. Bay Elev. 230.	1989	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-37	HD12SP07US	058	MS-1-1B drain	1989	

Main Steam and Feedwater:

None for RFO26.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**1E: Large Bore Components subjected to off normal flow conditions identified by turbine performance monitoring system (Systems Engineering Group).**

The Systems Engineering Production Variance Report for January 1 to January 31, 2006 lists 3 of the 10 normally closed Turbine Bypass Valves as suspected of having seat leakage. Elevated tailpipe temperatures (Approx. 250F vs. Approx 200F) have been recorded on valves 1, 5, & 7. (See Attached Plot). The tailpipes are 10 inch diameter carbon steel lines connecting directly to the condenser. Each line ends inside the condenser at multi-stage restriction orifice supplied by GE. This indicates that any pressure drop in these lines should occur inside the condenser. The steam temp at the bypass valve is approx 540F. The 250F temp measured on the three suspected leaking lines is approx. 50 F above the lines considered as not leaking. Any water condensing out of the steam should occur in the restriction orifices inside the condenser. Consider inspections on these lines only if temperatures continue to increase.

Since startup from 2005 (RFO25), only one small bore valve and no steam traps have been identified (to date) using the Turbine Performance Monitoring (TPM) system. The small bore valve is LCV-101-3B this is addressed in Section SD below. Piping Downstream of this valve, 2"-ES-9B is Cr.-Mo steel and is resistant to FAC. However, if new data indicates leaking valves then additions to the outage scope may be required.

**1F: Engineering Judgment / Other**

Nine ASME Section XI Class 1 Category B-J welds are to be inspected by the FAC program per Code Case N-560 in lieu of a Section XI volumetric weld inspection. The VY ISI Program Interval 4 schedule for inspection of these welds is as follows:

Refueling Outage	Section XI ISI Program Weld ID	Description	FAC Program Components
Spring 2004 (RFO24) Interval 4 Period 1, Outage 1.	FW19-F3B FW19-F3C FW19-F4 FW21-F1	upstream pipe to tee tee to reducer reducer to pipe tee to pipe	"A" Feedwater on Sketch 010 FD19TE01 FD19RD01 FD19SP04 FD21SP01
Fall 2011 (RFO29) Interval 4 Period 3, Outage 6.	FW18-3A FW20-3A FW20-F1 FW20-F1B FW18-F4	upstream pipe to tee tee to reducer reducer to pipe horizontal pipe to pipe tee to pipe	"B" Feedwater on Sketch 016 FD18TE01 FD20RD01 FD20SP01 FD18SP04

**Extended Power Uprate (EPU)**

Feedwater system:

EPU evaluation for Feedwater System: The primary focus of work to date (for PUSAR and RAls ) was on velocity changes given only slight increases in temps and no chemistry changes. With all 3 FDW pumps running the 16 inch diameter lines to the 24 inch FDW header have approx.  $[1.2(2/3) = 0.80]$  20% reduction in velocity. Velocities in the remainder of the system increase approx. 20%. The highest velocities are at the 10 inch reducers upstream and downstream of the FDW REG valves. The expander and downstream piping have multiple inspection data with FD07RD03/FD07SP03 last inspected in 2001 and FD08RD03/FD08SP02 last inspected in 2005. Both of these segments should be re-inspected after some time of operation at EPU flows. Assuming EPU starting early in 2006, inspect components FD07RD03 and FD07SP03 in 2007 for a post EPU measurement.

Continued

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

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**LF: Engineering Judgment / Other -continued**

**Condensate System:**

Given the 8/04 Mihama event, consider additional components in the condensate system for inspection :  
downstream of flow orifices & venturies:

FE-102-4 and downstream pipe on 24"C-8 venturi type (TB condensate pump room overhead) Given low operating temperatures and upstream of oxygen injection point, scope out and evaluate for inspection in RFO27 in 2008
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FE-52-1A to FE-52-1E on Condensate De-mineralizer System ( Restriction Orifices). Given low operating temperatures and upstream of oxygen injection point, scope out and evaluate for inspection in RFO27 in 2008
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FE-102-7 and downstream pipe on 14"C-21 venturi type TB Heater Bay El 237.5 Given low operating temperatures and used for start-up, scope out and evaluate for inspection in RFO27 in 2008
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**Extraction Steam**

All Extraction Steam piping is A335-P11, a 1-1/4 chrome material, except for a short carbon steel stub piece in line 12"-ES-1A at the connection to the 36" A cross around line. Internal visual inspections of this stub piece were performed with the cross around inspection in RFO24 and RFO25. Also an external UT inspection of ES1ASP01 was performed in RFO24.

**LG: Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)**

Word searches of open work orders on EMPAC were performed for the following keywords: trap, leak, valve, replace, repair, erosion, corrosion, steam, FAC, wear, hole, drain, and inspect. No previously unidentified components or piping were identified as requiring monitoring during the Fall 2005 RFO.

Note: the internal baffle plate in Condenser B for the AOG train tank return line to the condenser was to be replaced in RFO 25 (ER 04-1454/ ER 05-232 /ER 05-0274). Erosion on baffle plate is from condenser side (not piping side). This work was deferred from RFO25. See W.O. 04-1462.

Internal visual inspection of LCV-103-3A-2 during RFO 24 indicated some type of casting flaw. The System Engineer suspects possible leaking by the normally closed valve. The downstream piping was last inspected in 1990. The line typically has no flow. Re-evaluate using the Thermal Performance Monitoring System Data and consider inspection of downstream piping in RFO27.

A through wall leak in the steam seal header supply line 1SSH4 was discovered on 9/24/04 (CR-VTY-2004-02985). A temporary leak enclosure was installed and a planned permanent repair was scheduled for RFO25. The leaks are on the bottom of un-insulated piping upstream of the gland seal. Field inspection of the leak location shows that the piping at the leak sloping down to the gland seal, not sloping up to the seal as shown on the design drawings. UT data on the top of the piping near the leak shows full wall thickness. At this time, the exact mechanism which caused the leak is not known. Additional inspections to determine the extent of condition on the 3 other gland seal steam supply lines are were recommended. Inspection of the 90 degree elbow and approx. 2 ft. of downstream piping on lines 1SSH3, 1SSH4, 1SSH5, and 1SSH6 was planned for RFO 25. Also based on industry OE and similar piping geometry, inspection of 2 of the SPE lines 1SPE3 and 1SPE5 was planned for RFO 25. These inspections were deleted from the RFO26 scope due to higher priority LP turbine work. (References 9 & 10). Perform these inspections in RFO26. See Section LH below.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage  
Inspection Location Worksheets / Methods and Reasons for Component Selection**

**Small Bore Piping**

**SA: Susceptible piping locations (groups of components) contained in the Small Bore Piping data base which have not received an initial inspection.**

Locations on the continuous FDW heater vents to the condenser on the No. 3 heaters were inspected in 2002. The continuous vents on the No. 4 heater were installed new in 1995. The start up vents operate less than 2% of operating time. No wear was found in previous inspections on Heater Vent piping from the No. 1 & 2 heaters. Given that and the lower pressure in the No. 4 heater shells, a complete inspection of the remainder of the No. 4 heater vent piping can be deferred. The existing small bore data base and the piping susceptibility analysis is under revision. No additional components from Revision 1 of the data base will be inspected.

**SB: Components selected from measured or apparent wear found in previous inspection results.**

Small Bore Point No. 20. 2-1/2" MSD-6 @ connection to condenser A at Nozzle 33 (Inspection No. 96-SB01 identified a low reading at weld on stub to condenser). Upstream valves are normally closed. TPM system does not indicate any abnormal flow. Inspect this piping in RFO 26

**SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.**

Date	Plant - Type	Description & Recommended Actions at VY
4/29/99	Darlington 1 - PHWR	Severed line at steam trap discharge pipe at threaded connection. Equivalent to HHS system at VY. (INPO Event 931-990429-1) Threaded connections typically on condensate side of HHS piping. Lower energy/consequence of leak. <b>Include HHS piping in FAC Susceptibility Review, and in the Small Bore Database. Include ranking and consequences of failure.</b>
9/1/01	Peach Bottom 3 -BWR	(From 1/14/02 CHUG Meeting), leak on 1 inch Sch. 80 line from Off Gas Re-combiner pre-heater drain line to condenser. An additional review of AOG steam supply system was performed and incorporated into the FAC Susceptibility Review. <b>Update small bore database to include ranking and consequences of failure.</b>
1/15/02 CHUG Mtg.	Hatch 1/2 -BWR	Condenser in leakage due to through wall erosion (external) of 1-1/2 inch "slop" drains lines inside the condenser. Lines in each unit were cut and capped, similar events at Byron Unit 1 (OE 12609) and Columbia (OE12145). Limerick & Dresden. VY slop drain lines inside condenser were walked down during RFO24 and RFO25. Some external erosion on piping and supports was found. <b>Slop Drain Issue. Coordinate with Systems Engineer</b>
4/2/03	Peach Bottom 3 - BWR	OE16287: Steam leak found on 3"x2" elbow on RFP Turbine sealing steam system small bore piping. Leak was on piping susceptible to FAC but was not included in the scope of the FAC Program. This occurred as the piping was part of a vendor supplied skid and was not reflected on the drawings used for the FAC program. The VY FAC Susceptibility Evaluation has been updated to include all known vendor supplied piping (VY-RPT-05-00012, Rev.0.)
10/31/03	Clinton -BWR	OE17412 / OE18478: Through-wall leaks in 2A/B heater vent lines to the condenser (larger bore lines assumed given description of backing rings in piping). Apparent cause attributed to steam jet impingement from wet steam. Equivalent line at VY is common 4 inch feedwater heater vent line for No.4 FDW heaters. This line is included in the SSB database since it connects to (2) 2-1/2" lines. Inspection priority will be determined in the small bore ranking and prioritization.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
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SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI  
 CHUG. - continued

Date	Plant - Type	Description & Recommended Actions at VY
11/7/2003	Limerick 1, BWR	OE17818: Through wall leak in 1 inch drain line back to condenser off ES piping at the connection to the large bore line. Normally no flow in line due to N.C. valve. Piping downstream of valves to condenser on all 3 lines was scheduled for replacement. Location US of valve was thought not to be susceptible. ES piping at VY is FAC resistant A335-P1. Lesson from this event is that any carbon steel line in a wet steam system is susceptible & should be monitored. Also full line replacement insures all susceptible piping is replaced.
1/16/04	Clinton -- BWR	OE17654: Potential trend for adverse equipment condition downstream of orifices. (Ref. Previous experience a Clinton with CRD pump min flow ROs) Inspected CRD pump min flow orifices also piping DS of RO-64-2 in RFO25. Additional inspections will be performed if further OE is obtained.
12/06/04	V.C. Summer - PWR	OE19798/OE20075: Complete failure of a 1 inch ES line at the location of a previously installed Fernanite clamp repair. Previous leak at weld installed in May 2004. See presentation at January 2005 CHUG meeting. (They did not do UT on the pipe to assure structural integrity prior to installing the clamp.) Problems with leaving CS in system DS of material replacements. Review of previous replacements at VY has identified 2 locations at the condenser with similar configuration. Planned Inspections Nos. 07-SB04 and 07-SB05.
2/3/04	Columbia - BWR	6/04 CHUG Meeting PER: Through wall leak in 2" CS A106 Gr.B section of Misc drain line from bleed steam trap station to collection header. Location of leak is just upstream of where discharge piping enters the into the collection header. Piping upstream of location is stainless steel. At VY MSD piping downstream of ST-60A to 60D and LCV-101-38A to 38D connecting to 8"MSD-9 is carbon steel and is included in the Small bore Piping Database. Most locations have already been inspected. No further actions for this OE.
2/17/04	Peach Bottom 2 BWR	OE18637: On line leak in 10 inch main steam drain line header to the condenser. Hole was located directly below the connection of 1" main steam lead drain. The header was replaced with 1-1/4 Chrome material approx. 5 years before the leak. Also, ROs in steam drains were modified. The cause was attributed to steam impingement. Additional information to follow after next RFO. The only large bore drain collector at VY is the 8 inch diameter low point drain header, line 8"MSD-9. Flow is through steam traps and LCVs vs. a continuous flow through a restriction orifice. This line is now part of the AST ALT boundary. Inspections of the entire bottom of this header were performed during RFO24 with recommendations for repeat inspections in 2010. Also similar SSB configuration on 3"-MSD-4 near condenser. Inspect 3"-MSD-4 from the two 2 steam trap drains connections to the condenser.
3/2/04	Calvert Cliffs Unit 1 - PWR	OE18730: Though wall leaks in MSR drain piping at socket welded elbow fittings. Piping was replaced with Cr-Mo in the early 1990s. Cause attributed to liquid impingement. Plant is considering changing piping to eliminate SW elbows by using pipe bends. To date at VY: no leaks have been found on Cr-Mo piping replacements. No New action required for this OE.
5/9/04	Susquehanna Unit 2 - BWR	1/05 CHUG Meeting PER: Through wall leak in 1" Main Steam Bypass line drip leg drain to the condenser. The leak was at coupling joint at the condenser. The piping was replaced with P-22 in 1992. However, the coupling was not replaced at the condenser nozzle. A similar situation exists at VY for replacement of 2"MSD-406 (Steam Leads Drains) at the condenser. Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Insp. 07-SB04 at condenser Nozzle 35)

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG. - continued**

Date	Plant - Type	Description & Recommended Actions at VY
7/4/04	Hope Creek - BWR	1/05 CHUG Meeting PER: Through wall leak in 2" turbine bleed steam drain from HP extraction. Piping and coupling was 2-1/4% Cr-Mo. Leak attributed to abnormal fit-up into the coupling. Installation quality issue not FAC wear. No further actions for this OE.
10/1/04	Confrontes (Spain) - BWR	1/05 CHUG Meeting PER: Leak in 1-1/2" P-22 pipe bend on a turbine driven (feedwater) pump drain line in the Main & Re-Heated Steam System immediately downstream of an orifice. The only steam turbine driven pumps at VY are the HPCI and RCIC pumps. These pumps have low usage. No further actions for this OE.
12/8/04	TEPCO Fukushima1-4 - BWR	1/05 CHUG Meeting PER: Through wall leak in drain line from steam turbine driven feedwater pump steam supply line. The drain line runs to the condenser. The only steam turbine driven pumps at VY are the HPCI and RCIC pumps. These pumps have low usage. No further actions for this OE.
1/05 CHUG Meeting PER	River Bend - BWR	Through wall leak at condenser nozzle on the 2-1/2" emergency high level drain line from the steam seal evaporator drain receiver tank to the condenser. Sections of this line are stainless steel, but the condenser nozzle is carbon steel. The apparent cause is using this high level drain line for normal level control increased wear in the CS nozzle. The equivalent piping at line at VY is 3" and 6" C-44 downstream of valves LCV-102-8-1 and LCV-102-8-2 to condenser nozzle 63. Given that a leak in this line would affect condenser vacuum and challenge plant availability, inspect locations downstream of valves LCV-102-8-1 and LCV-102-8-2 in RFO26 (2007)
1/21/05	D.C. Cook 1 - PWR	OE20165: Leak in Middle Heater Drain Pump Emergency Leakoff Line assumed to have no flow when the pump was not running. Geometry different from North and South Heater Drain Pumps. However flow, was in the 1 inch line when the pumps were not running. Incorrect assumption in the FAC SSE. Assumption that pump was not in service and no flows in line. No additional inspections as a result of this OE. However, one of the DC Cook Corrective Actions should be performed at VY: "Assumptions used in the SSE will be re-validated to confirm they are still accurate". Generate PCRS/WT or ER to have reviews performed by Systems Engineers and OPS
2/4/05	TEPCO Kashiwazaki Kariwa (K-1) - BWR	6/05 CHUG Meeting Presentation and follow up at 1/06 CHUG Meeting PER**: Through wall leak at MS Leads Low Point Drains connecting to the condenser. Pipe 50A (approx. 2 inch dia.) Pipe material is Cr-Mo. Steel. Leak location is approx. 9 meters downstream of orifice in pipe on extrados of exit from a 90 degree SW. TEPCO root cause is two-phase flow incorporating droplet induced erosion. VY has similar geometry. Piping at VY was originally carbon steel and was replaced with Cr-Mo in 1998. TEPCO piping has a more tortuous path to the condenser (tee and 8 SW elbows) while VY only has the SW tee. **TEPCO plans to replace the line and move the RO into the condenser. Consider inspection of Cr-Mo Piping immediately DS of the SW tee in either 2008 or 2010 due to expected increase in drain flows at EPU conditions. CS stub piece at the condenser and upstream Cr-Mo piping will be inspected in RFO26 (2007).
3/1/05	McGuire 2- PWR	OE20163: Through-wall leak in a 2 inch carbon steel vent line on the MSR heating steam vent line. Caused by FAC when flashing occurred upstream of RO (design location). No MSRs or equivalent locations at VY. At VY the only Restriction Orifices are in the FDW Heater Vent System Continuous vent lines. These are already in the scope of the FAC program.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG. – continued**

Date	Plant - Type	Description & Recommended Actions at VY
6/05 & 1/06 CHUG Meetings	Peach Bottom Unit 3 -BWR	Through wall leak in RCIC Steam Supply Drain line to condenser. Location on CS section of line (running through the off gas pipe tunnel) which was not replaced with Cr-Mo P-11 material. The remainder of the line was previously replaced with P11. Event stresses importance of complete line replacements. A review of VYs combined HPCI/RCIC drains as shown on Drawing VYI-HPCI RCIC Drain Rev.1 and page 15 of JO file 89-0060 shows a carbon steel stub piece at the condenser was left in the line. <b>Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB05)</b>
6/05 CHUG Meeting PER	Wolf Creek - PWR	Pinhole leak in body of 2 inch MS drain line check valve due to erosion from leak-by through upstream steam trap. Thinning was found in 2" tee downstream of steam trap. At VY, piping downstream of MS steam traps has been previously inspected. Given expected increases in flow from EPU, piping DS of ST-60-3 will be inspected in RFO26 (Small Bore Inspection 07-SB02)
8/17/05 CHUG PER 1/06	Hope Creek - BWR	Through wall leak in 1-1/2" line from Steam Seal Evaporator Drain Tank to #3 FDW Htr. Temporary welded clamshell used for repair. Plant documentation indicated line was Cr-Mo P11 material. Lab analysis of metal filings indicates piping was carbon steel. No equivalent line at VY. However, note the installed material / documentation issue.
8/24/05 Presented at 1/06 CHUG Meeting	LaSalle Unit 1	Through wall leak in RCIC Steam Supply Pot Drain line to main condenser. Leak on straight section of pipe 11 ft D.S. of SW elbow. Major portion of line was replaced with Cr-Mo P-22 material. However this section running through a wall penetration was not replaced by field. Plant documentation indicated that the line was completely replaced. Event stresses importance of complete line replacements. Similar situation to peach Bottom leak presented at 6/05 CHUG meeting. A review of VYs combined HPCI/RCIC drains as shown on Drawing VYI-HPCI/RCIC Drain Rev.1 and page 15 of JO file 89-0060 shows a carbon steel stub piece at the condenser was left in the line. <b>Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB05 at condenser Nozzle 56)</b> Also, a similar situation exists at the previous replacement of 2"MSD-406 (Steam Leads Drains) at the condenser. <b>Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB04 at condenser Nozzle 35)</b>
9/14/05	Waterford 3 -PWR	OE21577: Pinhole leak in carbon steel drain line from Main Steam drip pot. Un isolable from the steam generator. Cause attributed to external corrosion, NOT FAC. Waterford has no turbine building and the MS drain piping is exposed to the weather. All steam process piping at VY is indoors. External corrosion is not a significant concern.
9/15/05 (1/06 CHUG Meeting PER)	Byron Unit 2 -PWR	Through wall leak in No.7 (highest) HP FDW Heater vent line to condenser. 2" schedule 80 line. Previous RT on elbows near FDW Heaters did not identify FAC wear. Location of wear in lines was toward the condenser. At VY all HP FDW Htr. vent lines were replaced with Cr-Mo in RFO24. <b>No further actions for this OE.</b>
9/23/05, 1/06 CHUG Meeting	Cooper -BWR	OE21586: Fatigue failure of 1-1/4" turbine slop drain piping inside condenser. Caused loss of condenser vacuum and manual scram. Lines were previously replaced in January 2005 due to external erosion from the steam space. Inadequate pipe supports and recent change out of LP turbines attributed as causes. RFO25 inspection at VY indicates piping has supports and some external surface wear is occurring. Markings on fittings indicate P-11 material is installed. This indicates previous replacements at VY. <b>Keep OE listed for future reference (Also reference: OE20044-Calvert Cliffs-1/05, OE20032-Palisades-1/05, OE20112-Oconee-1/05, OE19961-Turkey Point-12/04, OE13108-St. Lucie-9/01, OE12609-Byron-3/01, and OE12601-Hatch-10/00.)</b>



**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG. - continued**

Date	Plant - Type	Description & Recommended Actions at VY
9/21/05 CHUG PER 1/06	Nilo Mile Pt. 1 - BWR	Through wall leak in 1" GE supplied turbine Bypass Valve 2 <sup>nd</sup> stage leakoff line 2SLBPV line to SSH. Leak location at bend in 1" line off BPV. Similar layout to VY. VY has replaced the entire 1SLBPV line with Cr-Mo in RFO25. Previous FAC inspections on common 2-1/2" header to SSH line. No inspections in 1" lines. Schedule inspection of most probable BPV leakoff lines (1 to 10) based on ranking and consequences of failure in Small Bore Database.
11/15/05 CHUG PER 1/06	Peach Bottom 3 - BWR	Through wall leak in 1" schedule 160 Main Steam Leads drain downstream of orifice to condenser. Leak repair clamp installed. Equivalent piping at VY 2"MSD-408 Steam Leads Drains replaced with Cr-Mo steel except for piping stub at condenser. Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB04 at condenser Nozzle 35)
11/1/05 CHUG PER 1/06	Susquehanna Unit 1 - BWR	Through wall leak in 2" fabricated coupling in Steam Seal Evaporator Drain at Feedwater Nozzle (SSE drains to #2 FW Htr). Attached piping was replaced with Cr-Mo. However, nozzle fitting was never replaced. No equivalent line at VY.
1/06 CHUG Meeting	Diablo Canyon - PWR	Trough wall leak in 2 inch MSR LP Vent Condenser Drain line. Plant documentation indicated that all the lines were replaced with Cr-Mo material. Inspections subsequent to the leak found 6 pieces of carbon steel (not Cr-Mo) during the pipe replacements. Only found through in-situ alloy sampling. Plant includes alloy sampling in their large bore piping FAC inspections. Apparent Cause indicates problem with plant QA (replacements were part of a large fixed price contract). To date at VY, reviews of previous piping replacements have found no such discrepancies. This information should be factored into the evaluation whether or not alloy sampling should be incorporated into the VY FAC program.

**SD: Components subjected to off normal flow conditions, as indicated from the turbine performance monitoring system (Systems Engineering Group).**

The Systems Engineering Production Variance Report for January 1 to January 31, 2006 lists LCV-103-3B as having seat leakage to the condenser. Extraction Steam piping small bore valve is LCV-101-3B is a drain back to the condenser. Piping downstream of the valve on line ES-10B is Cr-Mo steel and is resistant to FAC. The piping was previously inspected in 1993 (Inspection No. 93-SB27) and in 1998 (Inspection No. 98-SB09). No further actions will be performed for RFO26.

Since startup from 2005 (RFO25), no other small bore valves and no steam traps have been identified (to date) using the Turbine Performance Monitoring (TPM) system. However, if new data indicates leaking valves then, additions to the outage scope may be required.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage  
Inspection Location Worksheets / Methods and Reasons for Component Selection**

**LH: Components "De-Scoped" (inspections deferred) from Previous Outages**

This is a new category. Planned inspections had never been deferred at VY before RFO25.

Inspection	Component	Evaluation / Reasons for Recommendation
2005-24 2005-25 2005-26 2005-27 2005-28 2005-29 2005-30 2005-31	1SSH3EL05 1SSH3SP06US 1SSH4EL01 1SSH4SP02US 1SSH5EL01 1SSH5SP02US 1SSH6EL08 1SSH6SP08US	Planned inspections on the turbine Steam Seal header (SSH) and the Steam Packing Exhauster (SPE) lines to determine the extent of condition for CR-VTY-2004-02985 CA 03 were "de-scoped" from the 2005 RFO due to higher priority LP turbine work in the same location.  Inspect these locations during RFO26 in Spring 2007.
2005-32 2005-33 2005-34 2005-35	2SPE3EL01 2SPE3SP01US 2SPE5EL01 2SPE5SP01US	Planned inspections on the turbine Steam Seal header (SSH) and the Steam Packing Exhauster (SPE) lines to determine the extent of condition for CR-VTY-2004-02985 CA 03 were "de-scoped" from the 2005 RFO due to higher priority LP turbine work in the same location.  Inspect these locations during RFO26 in Spring 2007.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage**  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

**Small Bore Piping**

**SE: Engineering judgment**

Look at piping DS of orifices based on BWR OE

Condensate: Given the 8/04 Mihama event: consider additional component in the condensate system for inspection downstream of flow orifices & venturies.

FE-102-6 and downstream pipe on 2 1/2" C-43 venturi type (TB heater bay elev. 230+/- Given low operating temperatures and upstream of oxygen injection point, **scope out and evaluate for inspection in R27 in 2008**

Main Steam Drains: Concerns with increased Moisture Carryover under EPU operating conditions: Inspect SSB components with may experience increase flow from EPU

Component	SSB DataBase Number	Location	Reasons/ Comments
1" & 2-1/2" Pipe & Fittings D.S. of Steam Trap ST-60-3	002	Rx Bldg. off Torus Catwalk - West	EPU concerns with increased Moisture carryover. Note this is part of AST ALT Boundary. Last inspected in 1993.
1" & 2-1/2" Pipe & Fittings D.S. LVC -2-143 of Steam Trap ST-60-3	003	Rx Bldg. off Torus Catwalk - West	EPU concerns with increased Moisture carryover. Note this is part of AST ALT Boundary. Last inspected in 1993.
2" CS pipe stub at Condenser wall on line 2"- MSD-406 at condenser nozzle 35 (Steam Lead Drains)	30B	Turb. Bldg. Heater Bay. Condenser A -North	EPU concerns with increased Moisture carryover. Also, recent industry experience OE with leaks in CS components in lines with partial material replacements.
2" CS pipe stub at Condenser wall on line 2"- HPCI/RCIC Drain line at condenser nozzle 56	33	Turb. Bldg. Heater Bay, Condenser B Northeast	Recent industry experience OE with leaks in CS components in lines with partial material replacements.

**SG:** Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

See LG above. The EMPAC search performed in LG above is applicable to both Large bore and Small bore components.

**SH:** Components "De-Scoped" (inspections deferred) from Previous Outages

None

### Feedwater Heater Shells

No feedwater heater shell inspections will be performed during the 2007 RFO. All 10 of the feedwater heater shells have been replaced with FAC resistant materials.

#### Recent / Relevant Industry OE Regarding Feedwater Heater Shells.

Date	Plant - Type	Description & Recommended Actions at VY
1/24/04	LaSalle Unit 1, BWR	OE18381/OE17919: Through indication indications in #2 LP feedwater heater extraction steam inlet nozzles. Carbon steel nozzles with Cr-Mo upstream piping. Similar situation existed at VY prior to replacement of all feedwater heater shells with FAC resistant materials. No new actions required at VY.
4/14/25	Browns Ferry 2 -BWR	OE20797: Higher wear rates than expected found in carbon steel Extraction Steam Inlet nozzles on No.3 LP feedwater heaters. Upstream pipe had been replaced with Cr-Mo and C.S. weld build-up had been performed on nozzles. Also a 105% power uprate increased flows. VY has Cr-Mo ES piping with either Cr-Mo Nozzles or S.S. nozzles. No further actions are required for this OE.
7/26/05 Presented at 1/06 CHUG Meeting	LaSalle Unit 1, BWR	OE:21384: Through Wall Leak in #3 LP feedwater heater shell. Htrs were scheduled for inspection at next RFO. Ranked as lowest priority due to high ES steam quality. Through wall erosion primarily caused by heater design with common axial location for HD inlet and outlet, and to ES inlet nozzles. Through wall leak determined to be result of weld defect (porosity) aggravated by FAC and leading edge effect.

**VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage  
Inspection Location Worksheets / Methods and Reasons for Component Selection**

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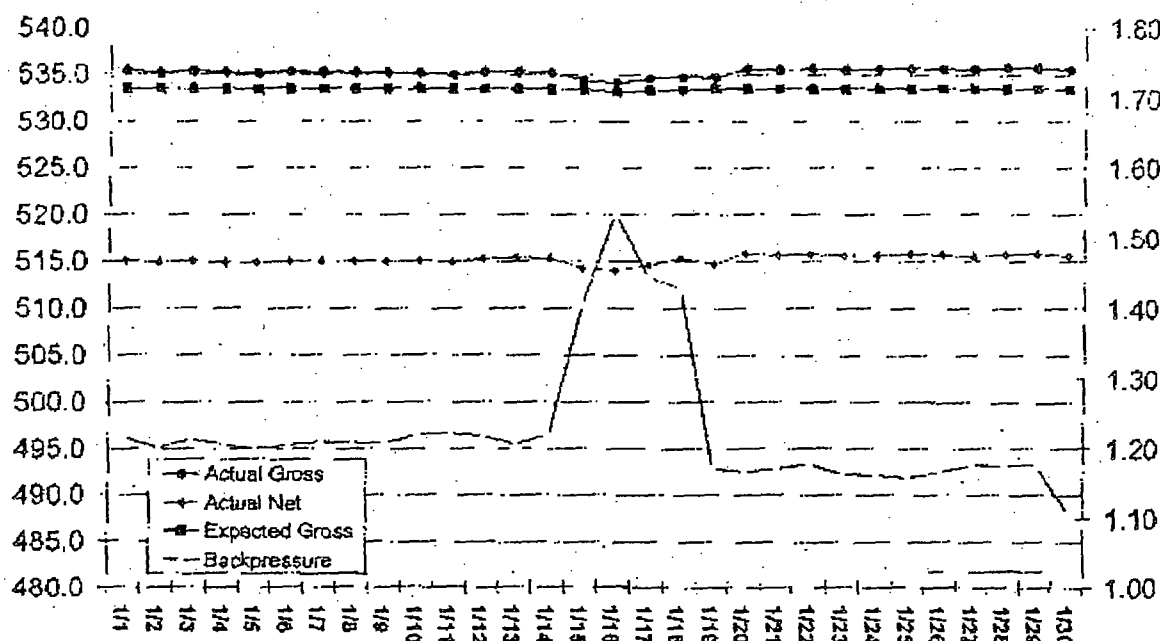
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7. VY-RPT-04-00010, Revision 0, "Vermont Yankee Piping Flow Accelerated Corrosion Inspection Program (PP 7028) 2004 Refueling Outage Inspection Report (RFO 24)"
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9. VYPPF 7102.01 RFO25 Scope Deletion of Restoration of TM 2004-031 (WO 04-4884-06), dated 10/24/05.
10. VYPPF 7102.01 RFO25 Scope Deletion of FAC Inspections 2005-24 to 2005-35 (WO 04-4983-000/010), dated 11/1/05.

**SYSTEM ENGINEERING  
PRODUCTION VARIANCE REPORT**

Vy 2007 01048  
RFO26  
SCOPING  
WORK SHEET

Actual vs. Expected Production January 1 to January 31, 2006



**EVENTS**

Date	Loss	Event
1/16/06	1 MWe/hr	Recirc Gate open to de-ice intake bay

**Full Power Averages For Previous Four Weeks**

- Actual Gross 535.3, Expected Gross 533.5, Net 515.2, Condenser Back Press: 1.22"HGA, Circ Water Inlet: 38° F, Average Difference in Heat Balance to actual: ~ 1.8 MWe (Gain)

**Known Losses (MWe per hour)**

	Loss	Tracking Item
• Operation < 1593	~ 0.1	N/A
• Actual Operation < Indicated Operation	~ 0.7	ER 04-1187
• LCV-101-3B Seat Leakage	~ 0.13	WO 05-4597
• Main Steam Bypass Valves 1,5 & 7	~ 0.85	PM due in RFO26

**System Engineering Observations and Recommendations:**

- High Circ Water traveling screen dp's resulted because of ice and debris flushed into the river from the heavy rains this weekend. The Control Room needed to open the Recirc Gate to de-ice the intake bay to address this. As a result, the Condenser is operating at a higher backpressure and net generation is down by approximately 1 MWe. This will not be categorized as a loss per the PI's because it is caused by environmental conditions beyond plant managements control.
- Lower backpressure was achieved on 1/31/06 by throttling open the SJAE suction valves, PCV-OG-516A/B. Opening these valves during EPU summer operation may provide for lower backpressure.
- Cycle Isolation has been restarted. A blown fuse was found, presumably as a result of the UPS-2A restart. The work order is being left open to troubleshoot several computer points that are not indicating properly.

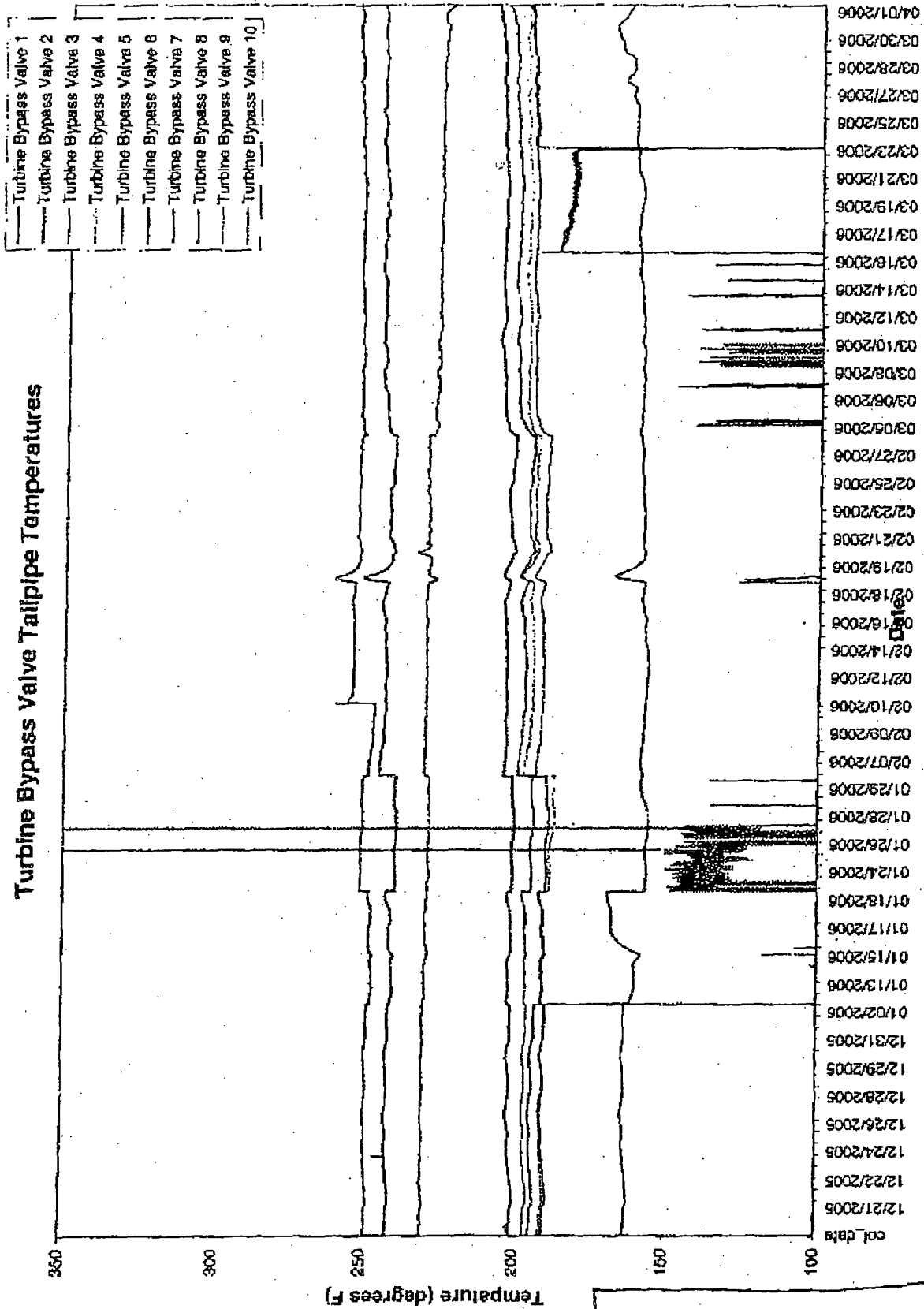
**Thermal Performance Work Status**


- Performed Heater Bay Thermography walkdown of un-instrumented high energy line valves to inspect for leaks during the 2/2/06 downpower. All valves inspected holding tight.

R246  
36 11

# Vy PRC Program RPO26 (2007) PRC SCOPING WORKSHEETS.

PRC



	QUALITY ASSURANCE DIVISION VERMONT YANKEE NUCLEAR POWER PLANT
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AUDIT NO.: -QA-8-2004-VY-1

TITLE: Engineering Programs

ACTION ORGANIZATIONS:

 Design Engineering  
 System Engineering

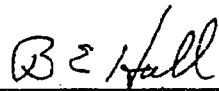
AUDIT TEAM:

B. E. Hall, ENNNY/QA,	ATL
H. Heilman, ENNNY/QA	ATM
Nick Love, Constellation	Tech Specialist

AUDIT DATES: 9/20/04 – 9/30/04Exit: 10/07/04

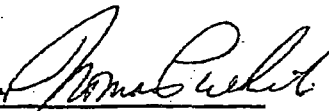
PREPARED BY:

B. E. Hall 11/22/04  
 Audit Team Leader / Date



APPROVED BY:

Thomas P. White 11/22/04  
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## EXECUTIVE SUMMARY

The audit team concluded that the four engineering programs evaluated during this audit, Reactor Vessel Internals, Check Valve, Relief Valve, and Environmental Qualification Programs were effective and were being administered and maintained in a manner that meets regulatory requirements/commitments and supports safe and reliable plant operation.

The team concluded that while the Flow Accelerated Corrosion Program was technically sound, a number of the administrative/documentation issues identified did not meet regulatory requirements.

The following table summarizes results for evaluated elements:

Elements	Result	Number of CRs/AFIs
EQ Program	Satisfactory	2 CRs 2 AFIs
Check Valve Program	Satisfactory	1 CR 3 AFIs
Flow Accelerated Corrosion Program	Unsatisfactory	2 CRs
Relief Valve Program	Satisfactory	1 CR 1 AFI
Reactor Vessel Internals Program	Satisfactory	1 CR 1 AFI

### Overall Results

The audit team identified five findings, two compliance CRs, and seven areas for improvement. None of the findings or areas for improvement, individually or in the aggregate, were indicative of significant programmatic weaknesses which would impact the overall effectiveness of the Engineering Programs assessed. However, as previously noted, there were administrative / documentation issues with the Flow Accelerated Corrosion Program which need to be corrected.

### Findings

RFO 24 FAC documentation not yet completed.  
(CR-VTY-2004-03061 Cat C – Design Engineering M&S)

QA records not handled in accordance with procedures.  
(CR-VTY-2004-03062 Cat C – Design Engineering M&S)

Multiple versions of MOVATS software in Check Valve Program.  
(CR-VTY-2004-03087 Cat C – System Engineering Components)

Relief valve as-found testing near miss.  
(CR-VTY-2004-03039 Cat B – Work Control)

QDR 8.6 does not clearly document how Amphenol connectors with Rexolite are qualified.  
(CR-VTY-2004-03032 Cat C – Design Engineering EI&C)

## Compliance

LO-CA issued instead of CR during IVVI Self-Assessment.  
(CR-VTY-2004-03086 Cat D – System Engineering Code Programs)

Master EQ List references deleted QDR 8.9.  
(CR-VTY-2004-03106 Cat D – Design Engineering EI&C)

## Areas for Improvement

LO-VTYLO-2004-00512

- CA - 1 The following documents need to be updated: OP 4223 needs to reflect new equipment, software, and practices. Vendor Manual VYEM 0250 needs to be evaluated to determine if it should be retained and updated or deleted.
- CA - 2 ESP training activities should be developed for the Check Valve Program similar to those for the MOV/AOV Program
- CA - 3 Submit VYAPF 0700.03 to training to get training credit for the two component engineers who completed off-site check valve diagnostic training.
- CA - 4 A maximum and minimum examination distance for the camera is established at the time of resolution demonstration check. Each examination record should indicate the distance the camera was from weld or verify that the camera was within the resolution range. The distance of the lens to the examination surface cannot be determined from the current QA records.
- CA - 5 The relief valve scheduling spread sheet should use the installation date rather than the as-found testing date to schedule the next test since the as-found test can be performed up to 90 days or one year after the valve is replaced. This can lead to incorrect due dates for the 48 month interval and the ten year mandatory test dates.
- CA - 6 The EQ Health Report should include all outstanding corrective actions related to EQ, not just those assigned to the EQ Coordinator. The current EQ Health report indicates no corrective actions are outstanding against the program. However, there are open corrective actions open to other departments for EQ issues. (CR-VTY-2001-00983 "EQ MCC Component Replacements Not Performed by End of EQ Life," Corrective Actions 1, 4, 8, 9, 13)
- CA - 7 The EQ Coordinator should note in the program health report the OEs that he had seen during the period of the report. Currently if no actions are taken there is no documentation that he has reviewed any OEs.

## AUDIT PURPOSE, SCOPE, AND METHODOLOGY

### Purpose:

The purpose of this audit was to determine whether selected Engineering Programs have been adequately maintained and administered to effectively meet regulatory requirements/commitments and support safe and reliable plant operation.

### Scope:

The selected engineering programs included the Environmental Qualification (EQ) Program, the Check Valve Program, the Flow Accelerated Corrosion (FAC) Program, the Relief Valve Program, and the Reactor Vessel Internals Program. Each program was checked to verify that it was being maintained current, that software used by the program was current and in the SQA program if applicable, and that required inspections/surveillances have been identified and implemented. In checking that the program was current, the impact of design changes, Extended Power Uprate (EPU), regulatory changes, deviations from codes and standards, industry positions, and industry experience was considered.

### Methodology:

The audit was performed through interviews with engineering personnel and others as appropriate and through the examination of procedures and documentation.

## AUDIT DETAILS

### Program Maintenance / Instructions, Procedures, Drawings

#### Plant Modifications

The audit team members concluded that adequate programmatic "hooks" existed to ensure that program engineers would be included in reviews of design changes affecting their programs and that programs have been adequately updated to reflect design changes. There was an exception noted in the EQ Program which is discussed below.

#### Environmental Qualification

During a review of several Qualification Documentation Review (QDR) Packages, it was noted that inboard electrical penetration Amphenol connectors were included in the Victoreen HRRM Package (QDR 8.6). The qualified life of these connectors was identified as 2.61 years. During a review of work orders to verify that the connectors had been replaced at the required frequencies, it was determined that new connectors were evaluated for this application per Equivalency Evaluation (EE) 1101. QDR 8.6 had not been adequately updated to reflect the new component with a longer qualified life. EE-1101 was considered inadequate because it did not reference the test report, a LOCFR50.49 requirement, needed to qualify the new connectors to IEEE-323. Thus, EE-1101 did not provide for an adequate evaluation of a critical characteristic for this EQ application. The EQ Program owner was unaware that these connectors had been replaced with a longer life component and wrote CR-VTY-2004-03032 to document the issue. An operability determination concluded that this issue was not an operability concern. This modification was not recent and changes made to the EE process should preclude recurrence.

The auditor also noted during the QDR reviews that the EQ Master List still referenced QDR 8.9.1 which had been previously deleted. CR-VTY-2004-03106 documented this issue.

#### Check Valve Program

Based upon a review of ENN and VY procedures, the auditor verified that the responsibilities of the Check Valve Program Coordinator (CVPC) included a review of plant design changes involving the addition, deletion, or change in station check valves. Although the CVP was not specifically included on the distribution of pending design changes, Component Engineering and/or the IST Coordinator were. Based on a discussion with the IST Program Coordinator, he has a good working relationship with the CVPC for interface of all aspects of the two programs. The review of design changes for program impact was discussed with the CVPC who stated that he would be included for review if a check valve was affected. He was included in the review of the EPU design change which added a third safety valve (he is also the Relief Valve Program Coordinator).

#### Flow Accelerated Corrosion

Section 3.2.12 of PP 7028 identified that one of the responsibilities of the FAC Inspection Program Coordinator is to "update/maintain the 'FAC Susceptible Piping Identification' document to reflect plant changes as required." Section 0.5 requires revision of the CHECWORKS module to reflect current plant design and operation. AP 6008 requires the Mechanical & Structural Group to review all VYDCs. AP 0020 also requires MMs to be reviewed by Mechanical & Structural unless it is checked NA for their review.

#### Relief Valve Program

Procedures PP 7204 and OP 4261 for IST and BOP valves include notes relative to changes to the program and equipment and the associated reference to the design document.

One pending change to the Safety & Relief Valve (S&RV) Program under ER-04-1222 was not routed to the program engineer for required review; however, the IST Engineer was a required reviewer for the change. The S&RV Program Engineer became involved when questioned on the need for pre-installation setpoint verification and provided input to the change originator by e-mail on 09/22/04. This omission was discussed with the originator who assumed that IST was the proper individual to respond. A further review revealed that ENN-DC-115, "ER Response Development," includes Programs and Component Engineering for impact screening. This appeared to be a misunderstanding and not a programmatic issue.

The auditor verified that procedure OP 4201 was revised by Maintenance Support to reflect the addition of a third safety valve installed for EPU.

Both procedure changes had the required documentation packages with approvals retained in Curator.

#### Reactor Vessel Internals Program

The Reactor Vessel Internals Program is driven primarily through the implementation of Procedure PP 7027, which maintains the inspections and examinations that are required under the BWRVIP Program. Although there are no current plant modifications that would affect this program, steam dryer cracking was being evaluated for scope increase. This was based upon the industry issues involving steam dryer cracking and the VY steam dryer cracks that were identified and repaired during RFO 24.

### **Extended Power Uprate**

Section 10, of Volume 2 of the "Vermont Yankee Nuclear Power Station Extended Power Uprate BOP Engineering Report" addresses the impact of the Extended Power Uprate (EPU) on various programs. Four of the five programs selected for this audit were addressed explicitly in section 10. The auditor considered that the fifth, Safety & Relief Valve was implicitly addressed as part of the 1ST Program. Based upon reviews of these sections and discussions with the program engineers, the auditors concluded that the impact of the EPU on Engineering Programs was being adequately addressed.

### **Environmental Qualification**

Due to temperature and radiation increases during accident scenarios, 181 pieces of equipment would need to be requalified and 1 modification was required. The EQ Coordinator stated that he was actively working on completing the required requalifications. As a check the auditor reviewed QDR 6.14, Rome XLPE/PVC Cable, which would be impacted. This review found the manner of evaluating qualification for radiation dose to be adequate and appropriate to assess increased dose from the power up-rate. No issues were identified with EPU impact.

### **Check Valve Program**

The main impact of the EPU would be on feedwater flow, steam flow and the generator. The report concluded that there would be no programmatic effect on the Check Valve Program, but that degradation rates could be affected by the EPU. Although it concluded that the normal inspection process should be adequate to identify changes in the valve degradation rate, it recommended that the program coordinator review the parameter changes caused by the EPU to identify any recommended testing or inspection frequency changes. The Check Valve Engineer has requested information on any velocity changes resulting from the EPU for further consideration of PM changes. The auditor had no further issues.

### **Flow Accelerated Corrosion**

The impact on the FAC Program of changes in the temperature, pressure, and velocity due to the power uprate were considered. Based upon evaluations of individual system impacts, it was concluded that there would be minimal impact on FAC and that no additional systems would need to be added to the FAC Program. The report also recommended new CHECWORKS runs to identify possible changes in FAC concerns (increased erosion rates, reduced useful components life, etc.). The new flows will be included in the new CHECWORKS model once version 1.0G is approved.

### **Relief Valve Program**

The EPU impact on the 1ST Program would be evaluated as part of the EPU change process. Modifications/changes are evaluated as part of the modification process for changes in system/component design requirements.

The Safety & Relief Valve Engineer indicated that he had been involved with EPU changes and had reviewed the design change packages. He has been satisfied with the interface between himself and the EPU staff. Pending procedure changes have been made to reflect the modifications made during RF024.

### Reactor Vessel Internals Program

The report noted that the In Vessel Visual Inspection (IVVI) Program was revised prior to each refueling outage. Since the EPU would be implemented following an outage, the program update prior to the outage should include any required EPU information [Dryer inspections and repairs were completed during RFO 24]. GE Task Report T0302, "Reactor Vessel Integrity Stress Evaluation," evaluated the expected EPU stress in many components/locations.

The auditor obtained and reviewed a copy of the "Licensee Identified Commitment Form" in accordance with ENN-LI-106, which demonstrated that a process was in place for preparing an action plan for the monitoring of the Steam Dryer. This document outlined a number of one-time commitment actions relative to the analysis, inspection and reporting actions and their respective scheduled completion dates. It was noted that several of the commitment actions had near term completion dates as well as indeterminate dates. A search of LOCRs using a key word of "steam dryer" showed that LOCRs had been written to track various steam dryer requirements.

### Regulatory Changes

The auditors concluded that regulatory changes were being adequately addressed. No issues were identified by the auditors.

### Environmental Qualification

There have been no recent regulatory changes impacting the VY EQ Program.

### Check Valve Program

Regulations mandating elements and testing of the Check Valve Program are Technical Specifications, the 1ST Program, and ASME OM-1998 Edition through ASME OMB-2000 Addenda. The Check Valve Program procedure has been revised for the new code requirements of the 4<sup>th</sup> 1ST interval.

### Relief Valve Program

Current 4<sup>th</sup> interval 1ST requirements for test frequency and expansion testing have been included in the Program procedure, PP 7204, "Safety & Relief Valve Program." Procedures have been revised to reflect the correct codes for the 4<sup>th</sup> 1ST interval.

### Reactor Vessel Internals Program

Program procedure PP 7027 "Reactor Vessel Internals Management Program" was reviewed, and was determined to address the necessary requirements for adequately implementing the BWRVIP Program. The procedure provides the necessary direction for the responsible individuals to review and initiate actions that may be required upon the issuance of NRC correspondence, information notices, BWRVIP documents and G.E. bulletins, etc., as they apply to Vermont Yankee. In turn, the information obtained from these documents is incorporated into the various inspection plans that are implemented during refueling outages.

To determine the adequacy of the prepared inspection plan, a comparison between PP 7027, Appendix A "Reactor Vessel Internals Components Inspection Scope and Schedule" and the RFO 24 Reactor Vessel Services In Vessel Visual Inspection Final Report was performed. Both were obtained from Curator. A sample of activities was randomly selected from the RFO 24 schedule, with respect to the method of examination and the relative frequency of the examination. These activities were compared with the RFO final report to determine if the appropriate examinations were performed. In all instances reviewed, the report confirmed that the required examination method and frequency were correct. In several instances, due to limited accessibility of the examined component, a partial examination was performed and documented as such. The assessor had contacted the Site Reactor Internals Engineer, to ascertain whether or not the examination sufficiently evaluated the component under examination. The engineer indicated that the inspection of the accessible portion of the component revealed no recordable indications, and was therefore deemed acceptable until such time that the reactor internals are accessible due to disassembly. The auditor subsequently confirmed that Technical Justification No. 2004-02, dated March 26, 2004 was issued for the deferral of inspection of inaccessible welds and Technical Evaluation No. 2004-0018 dated April 2004 addressed inspection of portions of shroud horizontal welds.

#### Code and Standards Deviations

Deviations from codes and standards, where applicable, have been adequately addressed. No issues were identified by the auditors.

#### Environmental Qualification

Based on discussion with the EQ Program owner, VY has not requested any deviations from NRC EQ Program requirements.

#### Check Valve Program

The Check Valve Program does not have deviations from approved codes and standards but implements and tracks deviations developed and approved under the 1ST Program. Several changes which were noted to valve testing/inspection frequencies were verified to be addressed with document changes, PM Basis Database changes, and EMPAC Asset schedule changes.

Changes from regulatory standards relative to the 4<sup>th</sup> interval 1ST Program and implemented or tracked through the CVP have been approved under NRC Letter NRY 03-078.

#### Flow Accelerated Corrosion

By letter dated March 19, 2001, VY requested approval from the NRC to use Code Case N-597 which was an alternative approach to evaluating components when the section thickness has been reduced below code minimum thickness. NRC approval was received by letter dated July 21, 2001.

#### Relief Valve Program

The 1ST 4<sup>th</sup> interval code deviations have been approved and accepted under NRC Letter NRY 03-078. The auditor verified that procedure OP 4201 referenced the proper codes for the 4<sup>th</sup> 1ST interval.

### Reactor Vessel Internals Program

Based upon spot checks the auditor confirmed that exceptions made due to weld accessibility and deferrals were documented and justified.

### Industry Alignment

In general, the auditors concluded that the programs reviewed were acceptably aligned with industry positions. As discussed below, VY's approach to the EQ Program is more fragmented than others, but this was discussed with engineering management who had already recognized some of these issues and was evaluating approaches to resolve them.

### Environmental Qualification

The QDR Packages reviewed had strong technical content and were organized in a manner that made the required information easy to find. This provides a strong basis for the program. Current industry efforts are focused on internal communications and retention of configuration control.

Based on review of procedure ENN-LI-100, ENN-DC-115 and ENN-DC-329, the recent implementation of these procedures at VY would appear to offer some enhancement to the oversight and feedback available to program owners. This may mitigate some of the potential for future disconnects between the maintenance organization's component replacements and engineering's oversight responsibilities.

However, these procedures which impact the EQ Program are partitioned in a manner that fragments program oversight accountability between licensing, engineering, and maintenance. ENN-LI-100 makes no reference to the EQ Program and ENN-DC-115 is a classification and screening process for engineering aspects only. The applicable procedures, including VY AP's offer only very limited flow charts identifying how the programs processes are supposed to work or how the various parts of the organization interface with each other. These issues were discussed with Engineering management.

Program health is a significant aspect of the INPO EQ Program Guideline currently in preparation. Audit health reports for quarter 2003-Q4 and 2004-Q1 were reviewed. The 2004-Q1 report indicates no CR CA's open against the EQ Program at this time. In fact, this is because the applicable performance indicator has been interpreted to apply only to CR CA's assigned to the EQ Program owner as opposed to those impacting the program as a whole. The industry position would be that the health report is intended to capture full program scope at the plant. CR-VTY-2001-0983 has five open items against it relating to non-performance of EQ component replacements. This issue was documented as CA6 of LO VTYLO-2004-00512.

### Check Valve Program

This scope element was discussed with the Check Valve Engineer. The program was originally developed based on the industry documents as identified in the program procedure purpose section and references. The review and inspection processes used in the development of the program are documented in curator under SOER 86-03. Corrective maintenance is factored into the program and subsequent PMs revised based on findings. Additional balance-of-plant check valves which were considered a risk to generation, but were not originally covered in the SOER 86-03, have also been included in the program. Based on a review of the type valves tested, the test methods, maintenance, intrusive and non intrusive inspections, the program and test methods appear to be in alignment with industry expectations.



### Flow Accelerated Corrosion

Surveillance 99-016 verified that the VY FAC Program met both NRC expectations and industry guidelines as defined in Generic Letter 89-08, "Erosion/Corrosion - Induced Pipe Wall Thinning

Program uses CHECWORKS, an EPRI sponsored code, as a tool for prioritizing inspections and tracking data. VY also participates in CHUG, an EPRI sponsored CHECWORKS user's group.

### Relief Valve Program

The S&RP was developed based upon EPRIINMAC guidance with recommendations from INPO included for balance-of-plant valves. The inputs and methodologies used in the development are discussed in the procedure as a historical reference. There have been no new initiatives in the area that are not included in the current program.

### Reactor Vessel Internals Program

Program procedure PP 7027 "Reactor Vessel Internals Management Program" was reviewed, and was determined to address the necessary requirements for adequately implementing the BWRVIP Program. The procedure provides the necessary direction for the responsible individuals to review and initiate actions that may be required upon the issuance of NRC correspondence, information notices, BWRVIP documents and G.E. bulletins, etc., as they apply to Vermont Yankee. In turn, the information obtained from these documents is incorporated into the various inspection plans that are implemented during the respective refueling outage.

During documentation reviews, it was noted that it could not be determined how the IVVI examinations were conducted, with respect to the measured distance between the lens of the camera and the examination surface. Procedure NE 8048, Rev. 1, paragraph 4.1.2 states in part, that "...the lens to object distance required to discern the target on the Sensitivity, Resolution, and Contrast Standard (SRCS) becomes the maximum distance examinations can be performed from the examination surface." Although the distance/range of the camera lens to the examination surface is determined and documented during the sensitivity, resolution and contrast standard, it cannot be readily determined how the distance is determined/maintained during actual visual examinations. This was addressed in CA 4 of LO VTYLO-2004-00512.

### Industry Events

All of the program engineers were receiving OE relevant to their program and were aware of significant industry events involving their programs. The auditors concluded that industry events were being adequately addressed.

### Environmental Qualification

As a part of the program health assessment, industry operational experience (OE) and NRC Information Notices (IN's) are to be screened for EQ Program impact. A sample of four recent OE's and three NRC IN's with potential EQ Program applicability were submitted to the Technical Support OE Coordinator to determine specifically how they had been addressed. All of the IN's were found in the Technical Support files with documentation to address the extent of their VY applicability including two which were evaluated to actually have direct EQ impact. One of these was entered in QDR 8.6 to address its specific applicability at VY.

Of the four OE's, all were distributed. Two were recognized as having potential EQ impact and sent to I&CIElectrical. None of the IN's and OE's reviewed by the auditor originated during the most recent two health report periods. However, while five additional OE's were issued during the 2003-Q4 and 2004-Q1 periods, none are noted as having been reviewed in the health reports. In discussions with the EQ Coordinator, he indicated that he does not normally identify OEs that he reviewed unless they required action. If no actions were taken, he does not document that he has reviewed the OE. The auditor recommended identifying in the program health report the OEs that he had reviewed during the reporting period even if no action was required. This was documented as CA 7 of LO VTYLO-2004-00512.

The EQ Program owner was very knowledgeable of industry events, and of the general applicability of operational experience at other plants to VY equipment.

#### Check Valve Program

The CV Program Engineer receives OE from the Entergy OE distribution as well as the System EPIX Coordinator. The OE evaluated each quarter is documented on the CV Program Health Report. A review of the last two health reports indicated that twelve OE related to check valves were reviewed. There were no specific changes to equipment, inspections or testing required from the reviews and no commitments resulted.

#### Flow Accelerated Corrosion

Industry events are identified and the bases for performing or not performing additional inspections were documented in the VY Piping FAC Inspection Program PP 7028 - 2004 Refueling Outage." The Coordinator was aware of the details of the piping failure that occurred in Japan and indicated that he has an action item (LO-OEN-2004-00272 CA-00003) to look for similar piping arrangements at VY.

#### Relief Valve Program

OE was discussed with the site OE coordinator, System Engineering EPIX Coordinator and the S&RV Program Engineer. OE that has been reviewed is documented in the Program Health Report. There has been no OE that required specific program changes or commitments generated. However, OP 4200 was revised based upon a concern received from Pilgrim Station involving hydrogen entrapment in the piping downcomer region. The S&RV Program Engineer receives OE for review from the ENN distribution as assigned by the morning screening as well as from the System Engineering OE screener. Seventeen OE reviews were documented in the health report.

#### Reactor Vessel Internals Program

Steam dryer cracking is currently the most significant industry OE issue in this area. This issue will drive further examination of this component in future examination/inspection activities. A Licensee Identified Commitment Form per Procedure ENN-LI-106 was initiated to identify specific actions that will be required to assist in the assessment of this component. This document contained commitments that will incorporate augmented examinations into the Vessel Internals Inspection Program.

#### Software/ Software Quality Control

With the exceptions noted below, the auditors considered that software was being adequately controlled. There were several issues identified with software QA, but none of them directly compromised the integrity of the results.

### Environmental Qualification

VY had EPRI's System 1000 software for materials library reference, but it was not yet in use because it had not been through the SQA Program. The EQ Database, which was developed in 1997, was included in the SQA Program as Level A software. However, the EQ Coordinator indicated that there had been a data corruption problem which IT had been unable to recover. The verified hard copy of the database is considered the Q copy. Since none of the EQ software was being used for Q purposes, this was considered acceptable.

### Check Valve Program

Check Valve Program software is classified as Category A and has been controlled through the procurement process. It has been approved and tested for verification. All paperwork for compliance was available as quality records in FYI.

Multiple versions of MOVATS software (4.6.b and 4.5) were still in use to support older equipment (Maintenance Support lap top computer). SQA paperwork for new versions state old versions are retired. The computer and software should be removed from use or the SQA should be resubmitted to define and allow conditional use of older versions (CR-VTY-2004-03087). Based on discussion with the MOVATS Component Engineer who was involved with all six RFO 24 non-intrusive check valve tests, the MOVATS computer with version 4.6.b software was used to perform diagnostic data collection and analysis.

The ENN web software catalog for VY, which is considered non Q, was not up-to-date for MOVATS software. It listed versions 4.0.0.0, 4.5, and 4.6. As mentioned before, version 4.6.b is the software of record and Curator records show that previous revisions are retired.

Based on discussion with the previous and current CV Program Engineers, one Signature Analysis Module (SAM) notebook computer is not capable of running the newer software. Version 4.6.b is capable of being used with the Viper and UDS systems. A potential area for improvement exists by updating OP 4223 to allow the performance of check valve diagnostics using any of the available systems. This was documented as CA 1 of LO-VTYLO-2004-00512.

### Flow Accelerated Corrosion

The Software QA Program identified CHECWORKS version 1.0F and CHECWORKS Application Manager Version 1.00 as approved software. The FAC Program Coordinator stated that he was in the process of upgrading to version LOG, but had not completed the software QA process. He had been using version 1.0F, but it was approved for a Windows 98 platform which was no longer available. Version LOG supports a Windows XP platform. Once the new version is approved, it can be used to confirm RFO 25 inspection selections and assist in the assessment of EPU impacts. The auditor considered this acceptable.

### Relief Valve Program

S&RV Program 1ST Scheduling software has been controlled and is appropriately classified as Type B in support of Technical Specifications. A review of the software qualification package revealed that all procedural requirements were met and are documented as QA records. No concerns were identified relative to Software QA requirement implementation. For the relief valve scheduling, the auditor noted an area for improvement in the use of the spreadsheet. There are no instructions for the spreadsheet use and currently, the date of as-found testing is inputted instead of the installed date. The as-found test date (performed subsequent to replacement) could cause the next test to exceed the 48 month or 10 year requirement to be exceeded (LO-VTYLO-2004-00512 CA 5).

### Reactor Vessel Internals Program

There were no specific software programs unique to the RVI Program.

### Inspections/Surveillances

The auditors concluded that required inspections and surveillances were being performed, although issues were identified with the completion of documentation in the FAC Program and with a scheduling error which could have led to missing a 90 day requirement in the S&RV Program.

### Maintenance of EQ Requirements

Based upon a review of Qualification Documentation Review (QDR) Packages to determine if adequate end of life replacements are being performed for components with qualified lives of less than 40 years, two examples were identified, one each for QDR's 8.8 and 35.3, where adequate replacements were made for items with qualified lives of 17.6 years and 3.3 years, respectively.

As discussed earlier, the review of QDR 8.6 identified that it had not been appropriately updated following an equivalent component replacement. A review of work orders verified that the new longer life components had been installed in the plant and was therefore not outside of its EQ lifetime.

### Check Valve Program

Required inspections and testing requirements are identified in the program procedure. The performance of the 2004 specified testing was evaluated through the review of 30 EMPAC work orders. All scheduled inspection and testing was performed, rescheduled with appropriate change documentation, or deleted from the 1ST/Check Valve Programs with justification documented. No concerns were noted.

### Flow Accelerated Corrosion

"VY Piping FAC Inspection Program PP 7028 - 2004 Refueling Outage" identified the inspections that were to be conducted during RFO 24. The Post outage report for RFO 24 had not been written at the time of the audit, although the program procedure requires that the report be issued within 90 days. The report for RFO 23, issued on 1/22/02 was reviewed by the auditor and found to be complete, thorough and met the expectations of PP 7028. However, this document had not yet been sent to RIMS. Based upon a search of CURATOR and discussions with the FAC Engineer, it was concluded that a significant amount of FAC Program documentation had not been sent to RIMS. These issues were documented in CR-VTY-2004-03061 and CR-VTY-2004-03062.

### Relief Valve Program

Required testing to meet code or program BOP valve expectations have been defined and tracked in the program procedure. A sample of nine 1ST valves scheduled for testing during 2004/2005 was selected for review. During the review of work orders and the P3 Work Week Schedule for the as-found testing, it was discovered that this activity was scheduled for 02/22/05 which would have been past the 90 day requirement. This had occurred in the past, with 4 CRs written in 2003. The corrective actions from these CRs did not prevent the potential recurrence of the same issue in this instance. CR-VTY-2004-03039 was written to address the near miss.

### Reactor Vessel Internals Program

On a sampling basis, the auditor verified that the scope of examinations/inspections required by the program procedure was performed during the In-Vessel Visual Inspection performed by AREVA. Of the components reviewed, the corresponding requirements were found to be consistent with the scope of work performed. No unsatisfactory conditions were noted.

Personnel certifications were also reviewed to verify that required personnel qualifications were current. All of the individuals responsible for performing the VT-1 and 3 Level II examinations were found to be qualified to perform these tasks during the duration of the RFO, and demonstrated the required visual acuity required to interpret their observations.

Additionally, the auditor verified on a sampling basis, that the individual in-vessel examinations did receive the required sensitivity, resolution and contrast verifications/calibrations. A comparison between the inspection data sheet and the resolution verification log was performed, which confirmed that the necessary resolution was maintained throughout the examination duration. It was observed in some instances, that the individual performing the calibration differed from the person who performed the examination. Upon investigating this concern, it was determined that this practice was acceptable, as none of the key elements of the examination, i.e. water clarity, lighting, nor equipment were affected, which would influence the video image. All of the individuals involved with the examination equipment calibration, performance and interpretation of results were verified to be qualified Level II or higher in the examination method used.

## Self Evaluation and Corrective Action Effectiveness

### Corrective Action Effectiveness

Based upon a review of the corrective actions associated with the Check Valve and the Safety & Relief Valve Programs, the auditor concluded that corrective actions were acceptable.

### Check Valve Program

Three QAD CRs that had been generated from surveillances were reviewed to determine if the corrective actions were acceptable, effective, and timely. Equipment issues were also reviewed. One level C and two Level B CRs were reviewed with no issues identified. Overall, CR dispositions were thoroughly performed with corrective actions assigned to address the most probable or apparent causes. Corrective action disposition has been timely with extensions minimal and approvals granted and justified when required.

### Safety & Relief Valve Program

Corrective actions from CRs and recommendations issued as a result of a 2002 QA assessment of the Safety and Relief Valve Program were also reviewed for acceptability, effectiveness, and timeliness. No concerns were identified.

ER-2003-1910 (Level I) for program deficiencies identified during the 2003 NRC PI&R Inspection was reviewed. The root cause investigation was performed to the AP 0009 requirements and commitments were established for the findings of the investigation. Corrective actions relative to the S&RV Program were reviewed

Condition Reports have been issued for each relief valve failure and programmatic issues. Since the NRC finding on the program and the corrective actions of CR-VTY-2003-1910, equipment failures have been assigned as Level "B." Improvements in the content of the evaluation and subsequent disposition are evident.

Based upon the CRs and corrective action reviewed above, the auditor concluded that commitments were tracked to completion with extensions documented and approved. Overall, corrective actions were considered timely and where delays existed, appropriate justification was provided.

### Self Evaluation Effectiveness

Based upon a review of selected self-assessments/benchmarks, it was concluded that the self assessments were of acceptable depth and were adequately intrusive. Recommendations were being tracked. It was noted that LOCs were used in two instances where CRs would have been more appropriate.

### Check Valve Program

A benchmarking trip was performed on OS116/04 to compare VY's Check Valve Program to that of Seabrook Station and included the CV Program Engineer, 1ST Program Engineer, and a mechanical maintenance support engineer. A review of the preliminary draft of the report revealed corrective actions would be issued for the evaluation of enhancements to the program. These included employing non-intrusive digital radiography methods, procedure enhancement for dimensional checks during disassembly and inspections, development of a condition monitoring process in support of IST, the use of leak rate testing results as a trending tool for determining check valve degradation, and an effectiveness of corrective actions review.

### Relief Valve Program

An on-going Self Assessment (MSA 2003-015) was performed under commitment OPVY-2003-065\_01. Recommendations resulting from the assessment were documented in the assessment and were entered into the corrective action process. The assessment included team members from the 1ST, Component Engineering, and Maintenance Support. The S&RV Program Engineer was aware of the status of all open items and is tracking the items under the program improvement plan.

### Reactor Vessel Internals Program

During the course of this assessment, a review of the BWRVIP Program Self Assessment that occurred following RFO 24, was performed. Although this assessment was found to be quite comprehensive, there were at two instances noted where LOCRs were written when CRs were the appropriate documents. Both examples involved the use of an incorrect examination method and frequency which were not in accordance with BWRVIP guidelines (VT-3 versus VT-1 visual exams). A failure to comply with BWRVIP guidance should have triggered a CR, not an LOCR. CR-VTY-2004-03086 was initiated to address this issue.

In both instances, the VT-1 examinations produced acceptable results. Recommendations within the self assessment indicate that the applicable tables in Procedure PP 7027 will be revised to capture the correct examination method and frequency requirements.

### Training/Qualifications

One of the five program engineer positions, EQ, had a qualification card item directly related to their EQ position at the time of the audit. The VY ESP Qualification Matrix indicated that position specific qualifications for all of the positions except the Reactor Internals Program Engineer were being developed for implementation across Entergy North. There is an ISI Engineer Qualification Card to be developed which could be used for the Vessel Internals. All of the current program engineers have had background, experience, and training relevant to their areas of responsibility.

Based upon a review of the training provided on check valves the auditor recommended that an ESP Qualification activity be established for check valve diagnostics and analysis equivalent to that for the MOV/AOV Programs. Also, since two component engineers had received off-site check valve diagnostic training, 0700.03 forms should be submitted to training to get training credit. (LO VTYLO-2004-0512 CA 2 and CA 3).

### Records/Document Control

While QA records and document control was acceptable within the Check Valve and Safety & Relief Valve Programs, temporary and permanent storage issues were identified within the FAC Program.

#### Check Valve Program and Safety & Relief Valve Programs:

Records reviewed from QA record files, packages in process, and Curator/FYI were legible and retrievable. Work order package records were legible with entries made in ink. Two instances were noted where a write-over or cross-out without initials occurred. However, this was a significant improvement over the condition of maintenance records reviewed on previous audits.

Work Order records that were completed and not transferred to RIMS were stored in the locked Work Control QA Records fire proof file cabinets. Incomplete records that have completed procedure data-sheets attached are not treated as QA records until complete. This was discussed with QA Records personnel in RIMS and is consistent with all records at the site for in-process work such as design changes and procedures where the package is not treated as a QA record until complete with the last signature. This interpretation is consistent with the QAPM and with ANSI 45.2.9.

## FAC

Based upon a review of data sheets from RFO 23, and 24 and documents retrieved from CURATOR, the records are legible. However, several issues were identified with document storage and transferal to RIMS.

Although the current records from RFO 24 were being maintained in a fire proof cabinet, other QA records such as the 2002 Refueling Outage Inspection Report (RFO 23 - Fall 2002) and supporting documentation were being maintained by the FAC Program Coordinator on a bookshelf.

As discussed earlier in "Inspections / surveillances, a significant amount of FAC Program documentation had not been sent to RIMS. These issues were documented in CR-VTY-2004-03061 and CR-VTY-2004-03062.

## LIST OF ATTACHMENTS

ATTACHMENT 1 - Personnel Contacted



**ATTACHMENT 1 - PERSONNEL CONTACTED**

Name	Department or Title	Contact
I. Dreyfuss	Director Engineering	1,3
J. Callaghan	Manager Design Engineering	1,3
J. Wierzbowski	Manager System Engineering	1, 3
A. Haumann	EQ Program Coordinator	1
E. Luciano	PM Coordinator, (C)	1
C. Rose	EPU, VY	1
I. Fitzpatrick	Senior Eng ME&S	1
S. Goodwin	Supervisor ME&S	1
J. Apostoles	Sr. Plant Mechanic, VY	1
W. Aho	VY OE Coordinator	1
T. Underkoffler	Appendix J Program Coordinator, VY	1
M. Garland	Mechanical Maintenance Supervisor, VY	1
J. Golonka	EPIX Coordinator, VY	1
R. Penny	Mgr, Eng Programs WPO	1
I. Lafferty	Sr Engineer (Nuc) WPO, VY IVVI Coord	1
W. Fields	Technical Spec IV (Nuc)	1
C. Larson	PNPS	1
J. Devincentis	Licensing Manager VY	1
L. Lukens	ISTPC, VY	1,3
B. Smith	Maint. Support Eng., VY	1
R. Booth	Check Valve Program Coordinator	1
T. Derting	IT SQA Program Administrator, VY	1
P. Longo	MOVATS Engineer, VY	1
M. Faunce	MOV Group Engineer	1
R. Wanczyk	Director, NSA	3
I. O'Connor	QA	3
S. DiMauro	QA	3
T. White	QAManager	3

1 - Contact

2 - Pre-Audit Conference - Informal

3 - Post-Audit Conference 10/07/04)

**Originator:** Hall, Bruce E**Originator Phone:** 5587**Originator Group:** Eng DE Manager**Operability Required:** N**Supervisor Name:** Callaghan, James H**Reportability Required:** N**Discovered Date:** 10/04/2004 13:24**Initiated Date:** 10/04/2004 13:28**Condition Description:**

QA records not handled in accordance with procedures

During Audit QA-8-2004-VTY-1, Engineering Programs, a number of noncompliances with plant procedures were noted, these included:

There is a significant backlog of FAC documents that have not been sent to RIMS. AP 6807, step 4.1.11.4 requires that QA records not be in temporary storage for more than 6 months.

Some QA documents that have not been sent to RIMS are not being stored in fireproof cabinets. AP 6807, section 4.1.1.1 requires completed QA records to be stored in 1 hr fire proof repositories.

CHECKWORKS predictive models have not been sent to RIMS for permanent storage as required by PP 7028, step 6.1.2

**Immediate Action Description:****Planned Action Description:****TRENDING (For Reference Purposes Only):****Trend Type**

KEYWORDS

CAUSE DEPT

HOW IDENTIFIED

KEYWORDS

HUTYPE

KEYWORDS

CAUSAL FACTOR CODES

HU EVALUATION FORM

KEY ACTIVITY

WORK PROCESS

**Trend Code**

KW-HU CLOCK RESET DEPT

CD-MECHANICAL - CIVIL/STRUCTURAL ENG.

HI-QAD

KW-PROCEDURE ADHERENCE

HU-PRECURSOR

KW-DOCUMENTATION PROBLEM

CFC-F4B4

HU-WB-PROCEDURE USE

KA-DS

WP-DM

**Version:****Significance Code:** C - MPC & CORRECT**Classification Code:** C**Owner Group:** Eng DE Mech Civil Struct Mgmt**Performed By:** Burger, Frederick J

10/05/2004 13:44

**Assignment Description:**

CR-VTY-2004-3062

Screening Data

☐ Significance DC - MPC & CORRECTDowner: ☐ Eng DE Mech Civil Struct Mgmt☐ Presented By: ☐ Goodwin, Scott

Comments:

DA Human Performance Evaluation VYAPF 0009.05 is required for all HU identified CRs

Trending Items

DOCUMENTATION PROBLEM

ERROR PRECURSOR-HU

HU CLOCK RESET DEPT

PROCEDURE ADHERENCE

QAD Identified

All paperwork that is planned to be transferred to RIMS has been temporarily placed in fire proof cabinets.

**Initiated Date:** 10/4/2004 13:28**Owner Group :**Eng DE Mech Civil Struct Mgmt**Current Contact:** FJB**Current Significance:** C - MPC & CORRECT**Closed by:** Felumb,Rhonda

3/22/2005 9:23

**Sununary Description:**

QA records not handled in accordance with procedures

During Audit QA-8-2004-VTY-1, Engineering Programs, a number of noncompliances with PP were noted these included:

There is a significant backlog of FAC documents that have not been sent to RIMS. AP 6807, step 4.1.11.4 requires that QA records not be in temporary storage for more than 6 months.

Some QA documents that have not been sent to RIMS are not being stored in fireproof cabinets. AP 6807, section 4.1.1.1 requires completed QA records to be stored in 1 hr fire proof repositories.

CHECKWORKS predictive models have not been sent to RIMS for permanent storage as required by PP 7028, steep 6.1.2

**Remarks Description:****Closure Description:**

Condition Report Closure Review IAW LI-102 Section 5.9.1 Completed

CA Number:

Group

Name

Assigned By: CRG/CARB/OSRC

Assigned To: Eng DE Mech Civil Struct Mgmt

Goodwin, Scott D

Subassigned To: Eng DE Mech Civil Struct Staff

Fitzpatrick, James C

Originated By: Burger, Frederick J

10/05/2004 13:48:55

Performed By: Goodwin, Scott D

11/02/2004 15:24:21

ubperformed By: Goodwin, Scott D

11/02/2004 15:23:28

Approved By:

Closed By: Felumb, Rhonda

11/02/2004 15:57:03

Current Due Date: 11/02/2004

Initial Due Date: 11/02/2004

CA Type: CR DISPOSITION

Plant Constraint: 0 NONE

CA Description:

CR Disposition

OQA records not handled in accordance with procedures

O(Review CR for Full Details)

CR-VTY-2004-3062

OReview Screening Comments on the Assignment Tab

O

OThe CRG has initially classified this CR as

JClassification Code - "C"

JSignificance Code - "MPC & CORRECT"

O

LJFollow the process provided in AP 0009 Appendix K. If during your investigations into this event it is determined that the classification should be changed, contact the CA&A representative for re-consideration by the CRG.

J

OPerform Most Probable Cause Evaluation. Issue the appropriate CAs. (per LI 102)

O

OCR Disposition Guidelines: This is only a guide. It is not a substitute for the applicable procedures.

L

OAll Attachments are to be in PDF format

O

OoAttach Most Probable Cause Investigation Report or Document in the Response or Sub response field

OoEnsure all Screening Comments have been addressed in the investigation - (CR assignment tab)

OoDevelop adequate corrective actions and issue CAs. (Due Dates per LI 102 Attachment 9.5)

Do LT CAs Require Approval from *Manager* GMPO or Director prior to initiating

OoAttach completed VYAPF 0009.02 (CR Trend Input Data Sheet) in accordance with Appendix E.

OoAttach completed VYAPF 0009.05 (Human Performance Evaluation) if required. Include Cause Dept

OooAttach completed EN-LI-118 Attachment 9.17 (Equipment Failure Evaluation Checklist) if assigned.

OoSpecify any references needed and enter into Ref. Items.

Response:

Review CRG Screening comments on Initiation Tab for inclusion in the report.

Subresponse:

QA records not handled in accordance with procedures.

'PC-1 [F.4.bA] Documents not followed correctly. FAC documents such as worksheets, reports, and CHECWORKS predictive models have not been sent to RIMS for permanent storage. Also, documents not sent to RIMS are to be stored in a fireproof cabinet until they have been transmitted

Immediate/Interim Actions Completed

Item #0 Action Taken

MPC-1 ☐ Placed documentation in fireproof cabinet until they are transmitted to RIMS.

☐

☐

Proposed/Assigned Corrective Actions

Item #	Action	CA Type	Assigned Department	Due Date	CA #
MPC-1	<input type="checkbox"/> Transmit FAC documentation to RIMS	CAODE	Mech Struct	3-18-05	000002
Closure of	CR	CA	DE Mech Struct	4-1-05	00003

Closure Comments:

Trending data entered and additional CAs have been generated.

Attachments:

Subresp Description  
Trend and HU

# Attachment Header

Document Name:

lcR-VTY-2004-03062 CA-00001

Document Location

Subresp Description

Attach Title:

Trend and HU

# ENVY HUMAN PERFORMANCE EVALUATION FORM

CR No: CR VTY-2004-03062	Dispositioning Dept: MSD
	Cause Department: MSD

<b>Applicable HU TRAPS:</b>		
<input type="radio"/> Time Pressure	<input type="radio"/> Vague Guidance	<input type="radio"/> Physical Environment
<input type="radio"/> Distraction/Interruption	<input type="radio"/> First Shift/Late Shift	<input type="radio"/> Mental Stress
<input type="radio"/> Multiple Tasks	<input type="radio"/> Peer Pressure	
<input type="radio"/> Overconfidence	<input type="radio"/> Change/Off-Normal	

<b>Description of Inappropriate Act(s):</b>	<b>Assoc Process/Prog/Org Issue(s):</b> <input checked="" type="checkbox"/> N/A
FAC personnel have not complied with procedures regarding the storage and/or transmittal of QA documents.	

<b>Worker Behaviors:</b>		
<input checked="" type="checkbox"/> Procedure Use/Adherence	<input type="radio"/> Self-Checking	<input type="radio"/> Fitness for Duty
<input type="radio"/> Placekeeping	<input type="radio"/> Peer Checking	<input type="radio"/> Turnover/Handoff
<input type="radio"/> Spoken Communication	<input type="radio"/> Knowledge	<input type="radio"/> Problem Solving Method
<input type="radio"/> Written Communication	<input type="radio"/> Skill	

<b>Supervisor Behaviors:</b>		
<input type="radio"/> Spoken Communication	<input type="radio"/> Task Allocation	<input type="radio"/> Pre-Job Brief
<input type="radio"/> Written Communication	<input type="radio"/> Clear Expectations	

<b>Management Behaviors:</b>		
<input type="radio"/> Communications	<input type="radio"/> Change Management	<input type="radio"/> Scheduling/Sequencing
<input type="radio"/> Resource Allocation	<input type="radio"/> Conservative Decision Mkg	<input type="radio"/> Clear Expectations

<b>Process/Programmatic/Organizational Issues:</b>		
<input type="radio"/> Ergonomic/Human Factors	<input type="radio"/> Housekeeping	<input type="radio"/> Procedure NVk Pkg Quality
<input type="radio"/> Environmental Conditions	<input type="radio"/> Equipment Labeling	<input type="radio"/> Training

Dispositioner: T. M. O'Connor	Date Completed: 11-2-04
-------------------------------	-------------------------



# CR TRENDING INPUT DATA SHEET

CR No: CR-VTY-2004-03062	Dispositioning Dept: MSD
	Cause Department (if HU): MSD

## NOTE

See Appendix E (CR Trending) for instructions on how to obtain information with which to complete this form

## CAUSE CODES

MPC-1 [F.4.b.4]

## KEYWORDS

Documentation

Procedure Adherence

## WORK PROCESS

OM

## KEY ACTIVITY

I

DS

I

**Entergy****CORRECTIVE ACTION****ICR-VTY-2004-03062**

CA Number: 2

**Group****Name**

Assigned By: Eng DE Mech Civil Struct Staff

O'Connor, Thomas M

Assigned To: Eng DE Mech Civil Struct Mgmt

Goodwin, Scott D

Subassigned To: Eng DE Mech Civil Struct Staff

Fitzpatrick, James C

Originated By: O'Connor, Thomas M

11/02/2004 14:04:41

Performed By: Goodwin, Scott D

031161200515:14:4S

Subperformed By:

Approved By:

Closed By: Goodwin, Scott D

03116/200515:14:4S

Current Due Date: 03/18/2005

Initial Due Date: 0311812005

CA Type: CORRECTIVE ACTION

Plant Constraint: 0 NONE

**CA Description:**

Transmit FAC documentation to RIMS

**Response:**

Transmittal is complete. Refer to e-mail enclosed as Att 1. No further actions required for this CA.

Subresponse :

**Closure Comments:****Attachments:**

Resp Description

FAC Doc Transmittal E-mail

# Attachment Header

Document Name:

untitled

Document Location

Resp Description

Attach Title:

FAC Doc Transmittal E-mail

**Goodwin, Scott**

**From:** Graves, Amy  
**Sent:** Wednesday, March 16, 2005 2:43 PM  
**To:** Goodwin, Scott  
**Cc:** Fitzpatrick, Jim; O'Connor, Tom  
**Subject:** FW: FAC INFO to RIMS for CR-VTY-2004-3062 CA2

Scott - Records indicated below have been transferred to RIMS in checklist number 02668. This transfer has been completed. Therefore, enabling you to close this commitment.

---

**From:** Fitzpatrick, Jim  
**Sent:** Monday, March 14, 2005 8:24 PM  
**To:** Graves, Amy  
**Cc:** Goodwin, Scott; O'Connor, Tom  
**Subject:** FAC INFO to RIMS for CR-VTY-2004-3062 CA2

Amy,

I have a CA to transmit FAC Program Inspection data and CHECWORKS Model data to RIMS by 3/18/03 (CR-VTY-2004-0362 CA2). There is a lot of data to be scanned.

The QA records for the 2004 RFO for the FAC Inspection program as required by PP 7028 have been assembled and indexed. They are located in the top drawer of the fire proof file in the PSB NW corner. The 2004 data package is similar to the 2001 RFO & 2002 RFO files previously sent to RIMS. These are originals so they should stay in the file.

In addition to the 2004 RFO inspection data there are 5 new documents to go to RIMS:

1. 1996 CHECWORKS Models & Results
2. 1996 EPRI CHECWORKS Database
3. 2001 EPRI CHECWORKS Database
4. EPRI CHECWORKS Wear Rate Analysis Results Cycles 20 & 21
5. EPRI CHECWORKS Wear Rate Analysis Results Cycles 22B

These are also in the top drawer of the fire proof file.

Please have these scanned and sent to RIMS. I will be out of the office the remainder of this week but can be reached at 603-778-1144. Also Tom O'Connor can help to identify items. Please tell Scott when the data has been transmitted so he can close out the CA or if you need more help.

Thanks,  
(Sorry for the data dump)

Jim Fitz.

Thanks,

Jim Fitz.

**Entergy****CORRECTIVE ACTION****ICR-VTY-2004-03062**

CA Number: 3

**Group****Name**

Assigned By: Eng DE Mech Civil Struct Mgmt

Assigned To: Eng DE Mech Civil Struct Mgmt

Subassigned To :

Originated By: Goodwin,Scott D

11/02/2004 15:09:40

Performed By: Goodwin,Scott D

03/16/2005 19:31:43

Subperformed By:

Approved By:

Closed By: Goodwin,Scott D

03/16/2005 19:31:43

Current Due Date: 04/01/2005

Initial Due Date: 04/01/2005

CA Type: EN CA

Plant Constraint: 0 NONE

**CA Description:**

Perform CR Closure review IAW EN-LI-102 requirements.

**Response:**

CR Disposition and all CAs have been reviewed and are considered closed. No further actions are required. IAW LI-102 requirements for closure, this CR should be closed.

Subresponse :

Sure Comments:

**Initiated Date:** 10/4/2004 13:23**Owner Group :** Eng DE Mech Civil Struct Mgmt**Current Contact:** FJB**Current Significance:** C - MPC & CORRECT**Closed by:** Felumb,Rhonda

2/16/2005 16:37

**Sununary Description:**

RFO 24 FAC documentation not yet completed

Formal documentation of FAC erosion rate on analysis/worksheets has not been completed for the data taken during RFO 24. The FAC Coordinator indicated that the Ultrasonic data had been reviewed, but the worksheets have not yet been completed to document the wear rate. Since the wear rates are not yet completed, the post outage FAC report has also not yet been completed although PP 7028, section 4.4.12 requires that the report be issued within 90 days.

**Remarks Description:****Closure Description:**

Condition Report Closure Review IAW LI-102 Section 5.9.1 Completed

Originator: Hall, Bruce E

Originator Phone: 5587

Originator Group: Eng DE Manager

Operability Required: N

Supervisor Name: Callaghan, James H

Reportability Required: N

Discovered Date: 10/04/2004 13:21

Initiated Date: 10/04/2004 13:23

**Condition Description:**

RFO 24 FAC documentation not yet completed

Formal documentation of FAC erosion rate on analysis/worksheets has not been completed for the data taken during RFO 24. The FAC Coordinator indicated that the Ultrasonic data had been reviewed, but the worksheets have not yet been completed to document the wear rate. Since the wear rates are not yet completed, the post outage FAC report has also not yet been completed although PP 7028, section 4.4.12 requires that the report be issued within 90 days. This condition report documents a QA identified issue. This issue was identified during the performance of Engineering Program Audit number QA-8-2004-VTY-1.

**Immediate Action Description:****Suggested Action Description:****TRENDING (For Reference Purposes Only):****Trend Type**

KEYWORDS  
KEYWORDS  
HOW IDENTIFIED  
HUTYPE  
CAUSE DEPT  
HU EVALUATION FORM  
WORK PROCESS  
HU EVALUATION FORM  
KEYWORDS  
CAUSAL FACTOR CODES  
CAUSAL FACTOR CODES  
KEY ACTIVITY  
HU EVALUATION FORM

**Trend Code**

KW-HU CLOCK RESET DEPT  
KW-PROCEDURE ADHERENCE  
HI-QAD  
HU-PRECURSOR  
CD-MECHANICAL - CIVIL/STRUCTURAL ENG.  
HU-TRAP-MULTIPLE TASKS  
WP-DM  
HU-TRAP-DISTRACTION  
KW-DOCUMENTATION PROBLEM  
CFC-E3Z4  
CFC-F4B4  
KA-AN  
HU-WB-PROCEDURE USE

**Initiated Date:** 10/4/2004 13:23**Owner Group :** Eng DE Mech Civil Struct Mgmt**Current Contact:** FIB**Current Significance:** C - MPC & CORRECT**Closed by:** Felumb,Rhonda

2/16/2005 16:37

**Sununary Description:**

RFO 24 FAC documentation not yet completed

Formal documentation of FAC erosion rate on analysis/worksheets has not been completed for the data taken during RFO 24. The FAC Coordinator indicated that the Ultrasonic data had been reviewed, but the worksheets have not yet been completed to document the wear rate. Since the wear rates are not yet completed, the post outage FAC report has also not yet been completed although PP 7028, section 4.4.12 requires that the report be issued within 90 days.

**Remarks Description:****Closure Description:**

Condition Report Closure Review LAW LI-102 Section 5.9.1 Completed



**Version:**

**Significance Code:** C - MPC & CORRECT

**Classification Code:** C

**Owner Group:** Eng DE Mech Civil Struct Mgmt

**Performed By:** Burger, Frederick J

10/05/2004 13:32

**Assignment Description:**

CR-VTY-2004-3061

Screening Data

OSignificanceDC - MPC & CORRECT

Downer: 0 Eng DE Mech Civil Struct Mgmt

DPresented By: 0 Goodwin, Scott

Comments:

DA Human Performance Evaluation VYAPF 0009.05 is required for all HU identified CRs

Trending Items

Cause Department -DE Mech Civil Structural

ERRORPRECURSOR-HU

HU CLOCK RESET DEPT

PROCEDURE ADHERENCE

Self-Identified

Discussed with FAC Coordinator. All RFO inspections have been evaluated and have been IR. There are no outstanding issues related to plant ops. Issue is administrative and relates to timely closure of paperwork.

**CA Number:**
**Group**
**Name**
**Assigned By:** CRG/CARB/OSRC

**Assigned To:** Eng DE Mech Civil Struct Mgmt

Goodwin, Scott D

**Subassigned To:** Eng DE Mech Civil Struct Staff

Fitzpatrick, James C

**Originated By:** Burger, Frederick J

10/051200413:41:55

**Performed By:** Goodwin, Scott D

11/0212004 15:27:15

**Subperformed By:** O'Connor, Thomas M

11/02/2004 15:09:38

**Approved By:**
**Closed By:** Felumb, Rhonda

11/0212004 15:50:51

**Current Due Date:** 11/02/2004

**Initial Due Date:** 11/02/2004

**CA Type:** CR DISPOSITION

**Plant Constraint:** 0 NONE

**CA Description:**

OCR Disposition

10RFO 24 FAC documentation not yet completed

O(Review CR for Full Details)

CR-VTY-2004-3061

OReview Screening Comments on the Assignment Tab

O

OThe CRG has initially classified this CR as

OClassification Code - "C"

OSignificance Code - " MPC &amp; CORRECT"

[J

OFollow the process provided in AP 0009 Appendix K. If during your investigations into this event it is determined

[Jthat the classification should be changed, contact the CA&amp;A representative for re-consideration by the CRG.

O

OPerform Most Probable Cause Evaluation. Issue the appropriate CAs. (per LI 102)

O

OCR Disposition Guidelines: This is only a guide. It is not a substitute for the applicable procedures.

O

OAll Attachments are to be in PDF format

O

OoAttach Most Probable Cause Investigation Report or Document in the Response or Sub response field

OoEnsure all Screening Comments have been addressed in the investigation - (CR assignment tab)

OoDevelop adequate corrective actions and issue CAs. (Due Dates per LI 102 Attachment 9.5)

00 LT CAs Require Approval from Manager/ GMPO or Director prior to initiating

OoAttach completed VYAPF 0009.02 (CR Trend Input Data Sheet) in accordance with Appendix E.

OoAttach completed VYAPF 0009.05 (Human Performance Evaluation) if required. Include Cause Dept

OooAttach completed EN-LI-118 Attachment 9.17 (Equipment Failure Evaluation Checklist) .if assigned.

OoSpecify any references needed and enter into Ref. Items.

**Response:**

Review CRG Screening notes on Initiation Tab for inclusion in report.

**Subresponse :**

FAC paperwork for RF024 not completed within 90 days of outage as required by procedure.

IPC-I [FA.bA] Documents not followed correctly; Procedure requires summary report to be issued within 90 days of outage completion. Although all data was evaluated and independently reviewed all formal worksheets had not been completed and hence the final report was not issued within the required time frame. Completion of formal worksheets is in progress with report to follow.

MPC-2 [E.3.zA] Contributing to the problem was ongoing work and emergent issues.

Proposed/Assigned Corrective Actions

Item #0 Action0

CA Type Assigned Department Due Date CA #

MPC-I OComplete FAC Worksheets and Issue Final Report DCAODE Mech Struct D 12-6-04000002

**Closure Comments:**

Trending data entered and additional CAs have been generated.

**Attachments:**

Subresp Description

trend and hu

## Attachment Header

Document Name:

CR-VTY-2004-03061 CA-00001

Document Location

ISUbresp Description

Attach Title:

trend and hu

# ENVY HUMAN PERFORMANCE EVALUATION FORM

CR No: CR-VTY-2004-03061	Dispositioning Dept: MSD
	Cause Department: MSD

<b>Applicable HU TRAPs:</b>		
<input type="checkbox"/> Time Pressure	<input type="checkbox"/> Vague Guidance	<input type="checkbox"/> Physical Environment
<input checked="" type="checkbox"/> Distraction/Interruption	<input type="checkbox"/> First Shift/Late Shift	<input type="checkbox"/> Mental Stress
<input checked="" type="checkbox"/> Multiple Tasks	<input type="checkbox"/> Peer Pressure	
<input type="checkbox"/> Overconfidence	<input type="checkbox"/> Change/Off-Normal	

<b>Description of Inappropriate Act(s):</b>	<b>Assoc Process/Prog/Org issue(s):</b> <i>NJA</i>
FAC personnel did not comply with procedure to complete RFO associated paperwork within 90 days of outage completion.	Multiple ongoing tasks and emergent issues contributed to paperwork not being completed in a timely fashion.

<b>Worker Behaviors:</b>		
<input checked="" type="checkbox"/> Procedure Use/Adherence	<input type="checkbox"/> Self-Checking	<input type="checkbox"/> Fitness for Duty
<input type="checkbox"/> Placekeeping	<input type="checkbox"/> Peer Checking	<input type="checkbox"/> Turnover/Handoff
<input type="checkbox"/> Spoken Communication	<input type="checkbox"/> Knowledge	<input type="checkbox"/> Problem Solving Method
<input type="checkbox"/> Written Communication	<input type="checkbox"/> Skill	

<b>Supervisor Behaviors:</b>		
<input type="checkbox"/> Spoken Communication	<input type="checkbox"/> Task Allocation	<input type="checkbox"/> Pre-Job Brief
<input type="checkbox"/> Written Communication	<input type="checkbox"/> Clear Expectations	

<b>Management Behaviors:</b>		
<input type="checkbox"/> Communications	<input type="checkbox"/> Change Management	<input type="checkbox"/> Scheduling/Sequencing
<input type="checkbox"/> Resource Allocation	<input type="checkbox"/> Conservative Decision Mkg	<input type="checkbox"/> Clear Expectations

<b>Process/Programmatic/Organizational Issues:</b>		
<input type="checkbox"/> Ergonomic/Human Factors	<input type="checkbox"/> Housekeeping	<input type="checkbox"/> Procedure/Wk Pkg Quality
<input type="checkbox"/> Environmental Conditions	<input type="checkbox"/> Equipment Labeling	<input type="checkbox"/> Training

Dispositioner: T. M. O'Connor	Date Completed: 11-2-04
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# CR TRENDING INPUT DATA SHEET

CR No: CR-VTY-2004-03061	Dispositioning Dept: MSD
	Cause Department (if HU): MSD

## NOTE

See Appendix E (CR Trending) for instructions on how to obtain information with which to complete this form.

## CAUSE CODES

MPC-1 [FA, bA]	MPC-2 [E, 3, 2A]	1
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## KEYWORDS

Documentation	Procedural Adherence
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## WORK PROCESS

AN

## KEY ACTIVITY

OM

CA Number: 2

## Group

## Name

Assigned By: Eng DE Mech Civil Struct Staff

O'Connor, Thomas M

Assigned To: Eng DE Mech Civil Struct Mgmt

Goodwin, Scott D

Subassigned To: Eng DE Mech Civil Struct Staff

Fitzpatrick, James C

Originated By: O'Connor, Thomas M

11/02/2004 14:30:15

Performed By: Goodwin, Scott D

02/15/2005 16:08:37

Subperformed By: Fitzpatrick, James C

02/15/2005 16:00:15

Approved By:

Closed By: Goodwin, Scott D

02/15/2005 16:08:37

Current Due Date: 02/15/2005

Initial Due Date: 12/06/2004

CA Type: CORRECTIVE ACTION

Plant Constraint: 0 NONE

## CA Description:

Complete Formal FAC worksheets and Issue Final Report

## Response:

Concur with response. No further actions required for this item. SDG 2-15-05

## Subresponse :

Attached .PDF file of 2004 RFO Outage FAC Inspection Report No. VY-RPT-04-00010 Rev.O.

Note the CD containing cross around piping photos is not included here. The CD and any other ENN DC-xx process forms are filed separately in the document control system as required by procedure.

## Closure Comments:

Approval attached to DDE #2.

## Attachments:

Subresp Description

VY-RPT-04-00010 RevO

# Attachment Header

Document Name:

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Document Location

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ISUBresp Description

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Attach Title:

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IV-RPT-04-0001O ReVO

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Engineering Report No. VY-RPT-04-00010 Rev. 0Page 1 of 20

Plus attached CD



ENTERGY NUCLEAR NORTHEAST

Engineering Report Cover Sheet

Engineering Report Title:

VERMONT YANKEE PIPING FLOW ACCELERATED CORROSION  
INSPECTION PROGRAM (PP 7028)  
2004 REFUELING OUTAGE INSPECTION REPORT  
(RFO 24- Spring 2004)

Engineering Report Type:

New ☒Revision 0Cancelled 0Superseded 0

Applicable Site(s)

IP1 DIP2 DIP3 DJAF DPNPS DVY ☒Quality-Related: ☒ Yes 0 No

Prepared by:

James C. Fitzpatrick

Responsible Engineer (Print Name/Sign)

Date:

2/15/05

Verified!

Reviewed by:

Thomas M. O'Connor

Design Verifier/Reviewer (Print Name/Sign)

Date:

2/15/05

\*Reviewed by:

N/A

Authorized Nuclear In-service Inspector (ANII)

Date:

N/A

Approved by:

Scott D. Goodwin

Supervisor (Print Name/Sign)

Date:

2-15-05

## Multiple Site Review (10)

Site	Design Verifier/Reviewer (Print Name/Sign)	Supervisor (Print Name/Sign)	Date
	N/A	N/A	N/A

\*: For ASME Section XI Code Program plans per ENN-DC-120, if required.

**Entergy****CORRECTIVE ACTION****ICR-VTY-2004-03061**

CA Number: 3

**Group****Name**

Assigned By: Eng DE Mech Civil Struct Staff

O'Connor, Thomas M

Assigned To: Eng DE Mech Civil Struct Mgmt

Goodwin, Scott D

**Subassigned To :**

Originated By: O'Connor, Thomas M

11/02/2004 15:07:55

Performed By: Goodwin, Scott D

02/16/2005 12:57:45

**Subperformed By:****Approved By:**

Closed By: Goodwin, Scott D

02/16/2005 12:57:45

Current Due Date: 03/04/2005

Initial Due Date: 12/20/2004

CA Type: CR CLOSURE REVIEW CA

Plant Constraint: 0 NONE

**CA Description:**

Ensure all Corrective Actions are closed out and close CR.

**Response:**

CR Disposition and associated CAs reviewed. All actions required complete. No further actions are required. IAW Section 5 of LI-102 this CR should be closed.

**Subresponse :****osure Comments:**

## Cornerstone Rollup

Program: Flow Accelerated Corrosion

Plant: VERMONT YANKEE

Quarter: 3rd

Last Update: 10/03/2006

Monitored Parameter	Criteria	Color	Total Quality Points	Comments
<b>Overall Program</b>	Green: 110 – 120 White: 85 – <110 Yellow: 75 – <85 Red: <75	Green	110	
<b>Program Personnel Cornerstone</b>	This cornerstone provides an indication of whether or not we have the right personnel with the right skills in the right positions to manage the program.	Green	26	
<b>Program Infrastructure Cornerstone</b>	This cornerstone provides an indication of the quality of the infrastructure in place to support the program. Infrastructure includes necessary equipment, program procedures, etc.	White	21	Corrective Action Plan to complete open LO-CA tasks developed 10/2/06 (CR-2006-02699)
<b>Program Implementation Cornerstone</b>	This cornerstone provides an indication of how well we execute programmatic requirements.	Green	33	
<b>Equipment / Related Plant Performance Cornerstone</b>	This cornerstone provides an indication of the health of the components (or other performance indicators impacting plant performance) monitored by the program.	Green	30	

Rev. 0

Date: 04-25-06

Attachment J

NEC038419

Personnel Performance Cornerstone					
Program: Flow Accelerated Corrosion					
	Plant:	VERMONT YANKEE			
	Quarter:	3rd			
	Last Update:	10/03/06			
	</				

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
(Includes any within the ENS region)	White – Active participation within industry within the past year with active sharing across sites.				(Voting and Advisory Committee access through single Entergy contact R.Jackson/RBS) Program owner member of CHUG Long Term Planning Group
	Yellow – No active involvement over the past year but active involvement within the past two years.				
	Red – Inactive participation.				

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Program Human Performance (Does not include errors in implementation)	Green – No HPEs over the past 12 months.	Green	1	3	No FAC Program related human performance error clock resets in the past 12 months.
	White – 1 HPE over the past 12 months				
	Yellow – 2-3 HPE over the past 12 months				
	Red – 4 or more HPE over the past 12 months				
Owner Availability	Green – Supervisor determines sufficient time is available for proactive program improvements	Yellow	2	2	Problems identified with timely update of CHECWORKS models (CR-2006-2699). CHECWORKS models and wear rata analyses updated with all previous inspection data in 3rd QTR 2006. Corrective Action Plan to prevent similar issues with remaining FAC program tasks developed 10/2/06.
	White – Supervisor determines sufficient time allotted for necessary program up keep.				
	Yellow – Supervisor determines insufficient time allotted for long term program up keep.				
	Red – Supervisor determines insufficient time allotted for immediate program needs.				
Peer Interaction (Does not include PI worksheet development)	Green – 2 or more peer	Green	1	3	Entergy FAC Program fleet call held on 7/26/06. EPRI CHUG Long Term Planning Group Telcons.
	White – 1 peer meeting/teleconference quarterly				
	Yellow – less than full regional participation for the meeting/teleconference within the quarter.				
	Red – Did not participate in peer meeting/teleconference for the quarter.				
			Total	26	

Infrastructure Performance Cornerstone					
Program: Flow Accelerated Corrosion					
	Plant: VERMONT YANKEE				
	Quarter: 3rd				
	Last Update: 10/03/2006				
	Cornerstone Rollup			Select Cornerstone Trending	
	Green: 26-30 cornerstone quality points	White		↑	Up
	White: 20-25 cornerstone quality points			→	Stable
	Yellow: 15-19 cornerstone quality points			↓	Down
	Red: <15 cornerstone quality points				
Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Program Infrastructure CRs (Internal) and External Findings. (External findings are defined as conditions found by independent oversight agencies resulting in A or B level CRs. Oversight agencies include QA [audits], INPO, and NRC.)	Green – (identified within the last two quarters)	Green	2	6	No program infrastructure related CRs this operating cycle. For 3rd Qtr. participated in development of new EN standard FAC program procedure EN-DC-315. EN-AD-101 RAF forms complete. Minimal impact to VY program for adoption of EN-DC-315.
	No A or B level CR AND				
	No external findings AND				
	< 4 C level CRs				
	White – (identified within the last two quarters)				
	No A level CR; AND				
	No external findings; AND				
	< 3 B level CRs; and AND				
	< 6 total B and C level CRs				
	Yellow – (identified within the last two quarters)				
	No A level CRs AND				
	Any of the following				
	3-4 B level CRs OR				
	5-15 total B or C level CRs OR				
	1 external finding.				
	Red – (Any of the following within the last two quarters)				
Any A level CR OR					
5 or more B level CRs OR					
15 or more total B or C level CRs OR					
2 or more external findings OR					
Any NRC violation.					

NEC038423

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Long Range Plan (plan for items requiring significant resources such as outage support requirements, scheduled assessments, program updates, critical infra-structure upgrades, and scheduled component replacements.)	Green – Long range plan in place covering the next 5 years, updated within the last year and with budgetary items IDd in the long range budget.	White	1	2	Completed transition to ENN standard FAC program this cycle. No formal long range plans have been developed for ENN FAC programs to date. However, VY has just implemented 120% power uprate. To assess effects on piping, the number of inspection locations will be increased approx 50% over previous outages for the next 3 refueling outages. Additional planning for small bore piping with respect to recommended replacements will be performed upon completion of VY-RPT-05-00013.
	White – Long range plan in place covering the next 3 years, updated within the last year and with budgetary items IDd in the long range budget.				
	Yellow - Foreseeable issues requiring significant resources within the 1 to 3 years not included in the long range plan.				
	Red – Foreseeable issues requiring significant resources within the next 12 months not included in the long range plan.				
	Yellow or Red can be upgraded once adequate plans are in place including funding in budget.				
Open Action Items (Includes ALL CR-CAs, ER post-action items and LO-CAs.)	Green – No due date extensions and no items greater than 6 months old.	Yellow	1	1	LO-VTYLO-2003-00327-CA2 LO-VTYLO-2003-00327-CA4 LO-VTYLO-2003-00327-CA6 LO-VTYLO-2004-00004-CA4 LO-VTYLO-2004-00399-CA1 LO-VTYLO-2005-00215-CA1 (Listed LO-CAs are tracked under Corrective Action Plan for CR-2006-02699)
	White – No action items greater than 1 year old.				
	Yellow – Any action item greater than 1 year old.				
	Red – 2 or more CR-CAs and/or ER post-action items (excluding LOs action items) greater than 1 year old.				
Document / Database Health	Green – No outstanding changes to the program documents (or databases) which impact program performance (e.g. missed commitment, surveillance past due); no outstanding changes for enhancements greater than two quarters old; and use of best-in-practice database or tracking software.	White	3	6	CHECWORKS models and wear rata analyses updated with all previous inspection data in 3rd QTR 2006. (CR-2006-2699)
	White – No outstanding changes to the program documents (or databases) which potentially impact program performance.				
	Yellow – Database compatibility issues OR any outstanding issues with the potential to impact program performance.				
	Red – Any procedural or database issue which directly impacted program performance within the past quarter.				



Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Test Equipment	Green – Best-in-practice, functional and properly calibrated equipment in the proper numbers to get the job done efficiently.	Green	2	4	Test Equipment (Parametrics UT/Data loggers) used during refueling outages is the same as used in the ISI Program. Equipment is tested and calibrated per NDE procedures prior to each refueling outage.
	White – Equipment functional and properly calibrated in the proper numbers to get the job done efficiently.				
	Yellow – Test Equipment Obsolescence Issues OR Test equipment failure (which did not impact scheduled or required program implementation activity) within the last quarter OR Insufficient equipment available (functional and properly calibrated) for efficient program implementation.				
	Red – Equipment unavailable to support scheduled or required program implementation activity.				
Benchmarks/Self-Assessments	Green: Benchmark or Self-Assessment within the last 2 years.	White	1	2	Next SA scheduled for completion 12/08/06 (LO-VTYLO-2003-00327-CA2)
	White: Benchmark or Self-Assessment within the last 3 years.				
	Yellow: Benchmark or Self-Assessment within the last 4 years.				
	Red: No Benchmark or Self-Assessment within the last 4 years.				
			Totals	21	

Implementation Performance Cornerstone					
Program: Flow Accelerated Corrosion					
	Plant:	VERMONT YANKEE			
	Quarter:	3rd			
	Last Update:	10/03/2006			
	Cornerstone Rollup			Select Cornerstone Trending	
	Green: 26-30 cornerstone quality points	Green		↑	Up
	White: 20-25 cornerstone quality points			↔	Stable
	Yellow: 15-19 cornerstone quality points			↓	Down
	Red: <15 cornerstone quality points				
Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Program Implementation CRs (Internal) and External Findings. (External findings are defined as conditions found by independent oversight agencies resulting in A or B level CRs. Oversight agencies include QA [audits], INPO, and NRC.)	Green – (identified within the last two quarters)	Green	1	3	CR-2006-2699 8/30/06 Level C, Identified CHECWORKS models were not updated in a timely manner. Problems identified with timely update of CHECWORKS models (CR-2006-2699). CHECWORKS models and wear rata analyses updated with all previous inspection data in 3rd QTR 2006. Corrective Action Plan to prevent similar issues with remaining FAC program tasks developed 10/2/06.
	No A or B level CR AND				
	No external findings AND				
	< 4 C level CRs				
	White – (identified within the last two quarters)				
	No A level CR; AND				
	No external findings; AND				
	< 3 B level CRs; AND				
	< 6 total B and C level CRs				
	Yellow – (identified within the last two quarters)				
	No A level CRs AND				
	Any of the following				
	3-4 B level CRs OR				
	5-15 total B or C level CRs OR				
	1 external finding.				

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
	Red – (Any of the following within the last two quarters) Any A level CR OR 5 or more B level CRs OR 15 or more total B or C level CRs OR 2 or more external findings OR Any NRC violation.				
Internally Identified Implementation Issues – Other than CRs (Self revealing issues, self assessments' benchmarking, Operating Experience including	Green: None White: Identified issue with action resolved. Yellow: Identified issue less than 1 year old. Red: Any identified issue greater than 1 year old.	Green	1	3	None (Issues addressed in Corrective Action Plan for CR-2006-2699 above)
Outage Performance Note: Indicator should remain the color until corrective actions are taken to preclude recurrence during the	Green: Met original scope and goals (duration, White: Less than 100% greater than 90% Yellow: Less than 90% greater than 80% Red: Less than 80%	Green	1	3	No Outage this Qtr. Outage planning milestones have been met.

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
On-line Performance	Green: Met original scope and goals (duration,	Green	1	3	No on-line FAC Related goals
	White: Less than 100% greater than 90%				
	Yellow: Less than 90% greater than 80%				
	Red: Less than 80%				
PM's/Surveillance Tasks (window stays the color until the deferred PM's are completed)	Green: No deferrals for the quarter	Green	1	3	No PMs under FAC program. Surveillances scheduled for RFO 26.
	White: Greater than 95% complete for the quarter				
	Yellow: Greater than 90% complete for the quarter				
	Red: Less than 90% complete for the quarter				
Other Identified Concerns or Issues (Only captures program concerns that do not fall under other PIs)	Green: No concerns / issues	Green	1	3	None. Internally identified implementation issues above addressed under (CR-2006-2699) Corrective Action Plan developed 10/2/06.
	White: Any non-significant concern/issue with action plan				
	Yellow: Any significant concern or issue with action plan or any non significant issue without action plan				
	Red: Any significant issue/concern without action plan				
Implementation resources (i.e. number of qualified personnel)	Green: No identified resource concern	Green	1	3	Currently 2 Program Engineers are qualified per ENN-TK-ESPG042 Training for new program engineer is process.
	White: Identified concern with action plan				
	Yellow: Identified concern without action plan				
	Red: Significant concern without action plan				
Piping Replacements (Unplanned during cycle or outage)	Green: 0 unplanned pipe or component replacements due to current outage findings.	Green	2	6	No outage this qtr. No unplanned piping replacements during this operating cycle. Possible FAC related small-bore replacement required in RFO26, (WO 06-6880) 1" SSH low pt.drain is in planning for RFO26.
	White: 1 unplanned pipe or component replacement due to current outage finding.				
	Yellow: > 1 < 2 unplanned pipe or component replacements due to current outage finding				
	Red - > 2 unplanned pipe or component replacements due to current outage finding.				

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
	(Note: Color can be up-graded once corrective actions to piping are completed and Program has been corrected to prevent recurrence; i.e., additional exams or exam frequency specified)				
Operating Experience	Green: 1 OR less items generated by plant OE department that has not been reviewed. White: 2 items generated by plant OE department that has not been reviewed. Yellow: 3 items generated by plant OE department that has not been reviewed. Red: > 4 items generated by plant OE department that has not been reviewed.	Green	1	3	No unreviewed OE generated by plant OE department.
Outage Scope Increase (Unplanned) (PWRs include online inspections in current cycle)	Green: < 10% increase in inspection scope due to inspection findings. White: 10% to < 12% increase in inspection scope due to inspection findings. Yellow: ≥ 13% increase in inspection scope due to inspection findings. Red: > 15% increase in inspection scope due to inspection findings.	Green	1	3	No unplanned outage scope increase to date.
			Total	33	

# Equipment / Related Plant Performance Cornerstone

Program: Flow Accelerated Corrosion

Plant: VERMONT YANKEE  
 Quarter: 3rd  
 Last Update: 10/03/2006

Cornerstone Rollup		Select Cornerstone Trending			
Green: 26-30 cornerstone quality points	Green	↑	Up		
White: 20-25 cornerstone quality points		↔	Stable		
Yellow: 15-19 cornerstone quality points		↓	Down		
Red: <15 cornerstone quality points					
Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Generation Health	Green - No Transients or power reduction resulting from a program issue	Green	2	6	No transients or power reductions resulting for program activities of FAC related leaks so far this operating cycle.
	White - No Transients or power reduction resulting from a program issue or component on a quarterly basis				
	Yellow - A "near miss", transient or a power reduction < 1000 mwhr/qt as a result of a program issue or component				
	Red - A plant trip or significant power reduction > 1000 mwhr/qtr as a result of a program issue of component				
Large Bore Failures (Based on Cycle of operation)	Green: No Large Bore failures in load	Green	4	12	No large bore failures this operating cycle
	Red: ≥ 1 Large Bore failure resulting in load reduction or safety issues.				
	Note: color can be up-graded once corrective actions to piping are completed and the Program has been corrected to prevent recurrence; i.e., additional exams or exam frequency specified)				

NEC038430

[illegible]

**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion (FAC) Program**

**AC**  
Controlling Document: PP 7028; ENN-DC-315

Owner: Jim Fitzpatrick

Phone: 802.451.3086  
Supervisor: Scott Goodwin

Date: 06-Apr-06  
Quarter: First Quarter, 2006  
Program Color: White  
Trend: Steady

2004-Q4	2005-Q1	2005-Q2	2005-Q4
---------	---------	---------	---------

**Current Status Basis:**

The FAC Program has just completed the 1st Qtr. 2006. (1/01 to 3/31)

Program is white, based on 20 Green, 3 White, and 1 Yellow indicators.

There are no outstanding issues which are not already addressed that may impact the program.

**Current Activities:**

1st Qtr. 2006 (1/01 to 3/31)

RFO25 FAC Outage Inspection Report

RFO26 Outage Program Scope Milestone 2/19/06. RFO26 FAC Scope Memo, VYM-2006-001 issued 2/16/06.

Adoption of ENN Standard FAC Program Procedure ENN-DC-315 Rev.1 on 3/15/06.

Attended EPRI Chechworks Users Group Meeting on 1/9 & 1/10. OE at meeting from LaSalle, Peach Bottom 3, and Surry on partial line replacements resulted in addition of three inspection locations for RFO26.

ENN FAC Working Group Meeting 1/26 at PNPS.

Participation in IPEC FAC Program Focused Self Assessment 2/6 to 2/10.

**Significant Accomplishments:**

Adoption of ENN-DC-315 Rev.1

Met RFO26 Outage Planning Milestone

**Actions To Return To Green:**

Current Program engineers still involved with EPU related tasks (Nuclear Change and Power Accension). Code Programs attempts at hiring a new Program Engineer have not yielded results to date.

Completion of identified tasks listed in the "Open LO-CAs" in this Program Health Report will bring Program status back to Green. To ensure that ongoing program tasks are re-scheduled and performed for remainder of 2006, the action plan per ENN-MS-S-008 will be revised and activities input to EWC by 4/15/06.

**Exceptions To Grading Criteria:**

NONE

**REGULATORY:**

**LERs:**

No FAC Program Related LERs this quarter.

**INPO Findings:**

No NRC Findings  
No INPO Findings or AFIs.

**GL 91-18 and Op Det:**

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

**Regulatory Compliance:**

The FAC Program currently meets all regulatory requirements.

**New FRs and Code Cases:**

New ENN Engineering Standard for Pipe Wall Thinning Evaluation, ENN-CS-S-008, incorporates ASME Code Case N-597. C.C. N-597 was incorporated into R.G. 1.147 Rev.13 with new caveats for use. NRC approval is required to implement code case as written.

**ADMINISTRATIVE:**

**Procedure, Program Compliance Issues:**

No Program Compliance issues with current Regulations of Codes.

With adoption of ENN-DC-315 Rev.1, VY Procedures PP7028 and DP0072 will be canceled per AP0096.

**Budget, Resources:**

FAC Program personnel (resources) were utilized on EPU related tasks. Currently no Program activities are scheduled into EWC. Activities will be input to EWC once scheduling of RFO26 design change work is complete.

Ownership of FAC Program to be transferred to Programs & Components Engineering. Currently interviewing for new FAC program Engineer position in Code Programs.

**Audits:**

No audits this quarter.

**Open Action Items:**

LO-VTYLO-2003-00327 CA 2 due 12/10/06 (three due date extensions)  
LO-VTYLO-2003-00327 CA 6 due 5/30/06 (two due date extensions)  
LO-VTYLO-2004-00399 CA 1 due 5/17/06 (two due date extensions)  
LO-VTYLO-2003-00327 CA 4 due 8/30/06 (two due date extensions)  
LO-VTYLO-2003-00327 CA 5 due 8/01/06 (two due date extensions)

**Benchmarking Self Assessment:**

Focused Self Assessment October 2003. Ongoing work for Corrective Actions generated from assessment. See LO-CAs (2003-0327) under Open Action Items

**EWC Milestones, New/Eng Issues:**

Continued difficulty in meeting re-projected schedules due to emergent work, EPU, & other unscheduled tasks. There is currently no EWC schedule in place for any Program. Program activities will be included in EWC after RFO26 design changes are scheduled.

A formal action plan per ENN-MS-S-008 to address issues to get program to Green status and ENN standardization was developed in 2nd. Qtr. 2005. Status has 4 of 11 tasks as not complete. A revision to the Action Plan and EWC scheduling will be performed when EWC is up and functioning.

**Program Concerns:**

Continued difficulties in completing scheduled FAC program activities due to resources spent on EPU related work. Concern from previous quarters. A formal Action Plan per ENN-MS S-008 was developed to get program to Green status.

Lack of progress in hiring a new FAC Program Engineer for Code Programs is a concern.

**CORRECTIVE ACTIONS:**

**Significant CRs:**

No significant CR's (Category A or B) were written against the FAC program for this quarter.

**Open CR CAs:**

No open CRs as of 3/31/06

**EQUIPMENT:**

**Open Eng Req:**



**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion (FAC) Program**

**FAC**

**Owner:** Jim Fitzpatrick

**Phone:** 802.451.3086

**Controlling Document:** PP 7028; ENN-DC-315

**Supervisor:** Scott Goodwin

ER 04-1315 for Evaluation of Temporary Steam Leak Repair on L.P. Turbine Steam Seal Piping

ER 05-0767 for Converting FAC Component Location Sketches Located into Appendix A of PP7028 into Controlled VY Drawings

ER 05-1004 for Updating FAC Program Checworks Models for RFO26.

**Operator Work Arouds:**

N/A - There are no operator works arounds related to the FAC program.

**Prog Related LCOs:**

There are no LCOs related to the FAC program this qtr.

**PMs Within Due Date:**

N/A - There are no PMs associated with the FAC program.

**Repetitive Failures:**

There are no repetitive equipment related issues for the FAC program this quarter.

**Unanticipated Failures:**

SSH pin hole leaks identified in CR VTY-2004-02985. Temporary leak enclosure installed. Additional inspections of similar piping incorporated into scope of RFO25. However, inspections were deferred until RFO26 due to schedule for LP turbine work.

No new Unanticipated Failures since October 2004.

**Trending Results:**

No components projected to wear to wall thickness below code minimum within two cycles from RFO26.

**Open Work Requests:**

N/A - There are no work requests over 2 yrs old.

**Surveillances Within**

**Due Date:**

N/A No Technical Specification Surveillances under the FAC program this quarter.

**Significant Parts Issues:**

- There are no parts issues associated with the FAC program this quarter

**Identified Concerns:**

No other identified equipment concerns.

**ORGANIZATION:**

**Staff Qualification:**

The program owner and Backup engineer are qualified to perform FAC Program tasks.

3rd Engineer obtained basic FAC training and CHECWORKS SFA training, June 6-8.

**Bench Strength:**

The program owner and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in Civil/Structural (R. Omer) has FAC related experience and has completed updated FAC training.

**Program Ownership:**

Site personnel are aware of the Program. Owner based results from last SA.

FAC Program Ownership to be transferred to Code Programs Group per ENN model. Interviews for a new FAC Program Engineer to reside in Code Programs started in October 2005.

**HU Errors:**

There were no human performance errors (HPE) as a result of Program implementation activities for this quarter.

**AP0098 Expectations:**

Continued difficulties in completing program activities on schedule. EPU work is still affecting FAC Program activities in 1st quarter of 2006.

A formal action plan per ENN-MS S-008 to get program Green status and address ENN standardization issues was developed. The ENN standization efforts are complete as of 3/15/06 with the exception of cancelling PP7028 & DP0072 per AP0096. All other tasks required are being tracked in PCRS. Completion of identified tasks listed in the "Open LO-CAs" in this Program Health Report will bring Program status back to Green.

Status: Progress needs to be monitored. Keep status as White

**Operating Experience:**

See RFO26 (2007) Scoping Worksheets for a detailed list of FAC related OE and disposition for VY.

**ECIs:**

None

**Outage Health:**

**Outage Perf:**

No refueling outage in 1st QTR 2006.

RFO26 program scoping Milestone of 2/19/06 met (Memo VYM-FAC-2006-001 dated 2/16/06).

**Outage Preparation:**

RFO26 Outage planning milestones met.

**Generation Health:**

**Generation Health:**

There were no transients or power reductions as a result of a FAC Program issue in 1st quarter of 2006.

**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion (FAC) Program**

**FAC**

**Owner: Jim Fitzpatrick**

**Phone: 802.451.3086**

**Controlling Document: PP 7028; ENN-DC-315**

**Supervisor: Scott Goodwin**

Date: **15-Mar-06**  
Quarter: **Fourth Quarter, 2005**  
Program Color: **White**  
Trend: **Steady**

2004-Q3	2004-Q4	2005-Q1	2005-Q2
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**Current Status Basis:**

This report covers 3rd & 4th quarters of 2005.

Program is White, based on 17 Green, 6 White, and 1 Yellow indicators.

There are no outstanding issues which are not already addressed that may impact the program.

**Current Activities:**

3rd & 4th Qtr. 2005 (7/1/05 to 12/31/05)

RFO25 Outage Planning & Preparation

NRC FAC Program Inspection week of July 25

• Susceptibility Evaluation updated for EPU and other piping design changes (VY-RPT-05-00012, Rev.0)

Transition efforts to adopt ENN Standard FAC Program Procedure ENN-DC-315 Rev.0:

1. Gap Analysis with PP7028 Completed 9/14/05
2. ENN-LI-100 Att.9.1, ENN-LI-101 Att.9.1 and EN-AD-101 Att.9.1 with VY comments sent to WPO on 9/22/05.
3. Engineering Standard & Approval form for ENN-CE-S-008 Pipe Wall Thinning Structural Evaluation, Rev.0 for VY completed 9/22/05.
4. Engineering Standard & Approval form for ENN-EP-S-005 FAC Component Scanning & Gridding Standard, Rev.0 for VY completed 9/22/05.

J. Fitzpatrick and T. O'Connor completed documentation for ENN standard FAC Qual Card ENN-TKESPG-042 on 10/5/05

RFO25 outage support, data evaluations and trending of inspection results.

Provided support for Management Presentations at ACRS Power Update Subgroup on Power Upgrades Meeting in Bethesda, MD on 11/30 & 31.

**gnificant Accomplishments:**

NRC FAC Inspection Complete. No findings of significance were identified. NRC Inspection Report for VY 2005-004

dated October 19,2005).

Support of RFO25 inspection efforts

**Actions To Return To Green:**

Ensure that ongoing program tasks which were re-scheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo are in fact performed on or near to schedule. This requires adequate time & personnel be allotted to perform program tasks. A formal action plan per ENN-MS-S-008 to get program Green status and address ENN standardization issues was developed in May 2005. Status 8 of 9 items complete in 2005.

**Exceptions To Grading Criteria:**

NONE

**REGULATORY:**

**LERs:**

No FAC Program Related LERs these quarters.

**INPO Findings:**

No NRC Findings  
No INPO Findings or AFIs.

**GL 91-18 and Op Det:**

No GL 91-18 issues or operability evaluations related to the FAC Program these quarters.

**Regulatory Compliance:**

The FAC Program currently meets all regulatory requirements.

**New RRs and Code Cases:**

New ENN Engineering Standard for Pipe Wall Thinning Evaluation, ENN-CS-S-008, effective date 9/28/05, incorporates ASME Code Case N-597. C.C. N597 was incorporated into R.G 1.147 Rev.13 with new caveats for use. NRC approval is required to implement the code case as written.

**ADMINISTRATIVE:**

**Procedure, Program Compliance Issues:**

No Program Compliance Issues with current Regulations of Codes.

PP7028 and DP0072 to be cancelled once ENN-DC-315 is made effective at VY.

**Budget, Resources:**

2004 and 2005 scheduling of FAC

Program per ENN-DC-183 Program Scoping Memo. FAC Program personnel (resources) were utilized on EPU related design changes and calculations. EWC schedule has Program resources pushed back to 2nd half of 2005.

Ownership of FAC Program to be transferred to Program & Components Engineering. Currently interviewing for new FAC Program Engineer position in Code Programs.

**Audits:**

An NRC Inspection of the FAC Program for addressing EPU changes to piping and operating conditions was conducted the week of July 25,2005. No findings of significance were identified. (NRC Inspection Report for VY 2005-004 dated October 19,2005).

**Open Action Items:**

LO-VTYLO-2003-00327 CA 2 due 1/13/06 (two due date extensions)  
LO-VTYLO-2003-00327 CA 6 due 5/30/06 (two due date extensions)  
LO-VTYLO-2004-00399 CA 1 due 5/17/06 (two due date extensions)  
LO-VTYLO-2003-00327 CA 4 due 2/10/06 (one due date extension)  
LO-VTYLO-2003-00327 CA 5 due 1/15/06 (one due date extension)

**BenchMarking:**

**SelfAssessment:**

Focused Self Assessment October 2003. Ongoing work for Corrective Actions generated from assessment See LO-CAs (2003-0327) under Open Action Items

**EWC Milestones, New Eng Issues:**

Ongoing program tasks were rescheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo. Continued difficulty in meeting re-projected schedules due to emergent work, EPU, & other unscheduled tasks. A formal action plan per ENN-MS-S-008 was developed in 2nd. Qtr. 2005.

Action Plan addresses issues to get program to Green status and ENN standardization. All items on action plan completed in 2005 except incorporation of Small Bore Database into VY-RPT-05-00013. This work is inprocess.

**Program Concerns:**

Scheduled FAC program activities were started late in 3rd quarter due to resources spent on EPU related work. Concern from previous qtr. A formal Action Plan per ENN-MS-S-008 was developed to get program status Green and address ENN

**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion (FAC) Program**

**FAC**

Owner: Jim Fitzpatrick

Phone: 802.451.3086

Controlling Document: PP 7028; ENN-DC-315

Supervisor: Scott Goodwin

standardization issues.

Progress was made on action plan items. However, the root cause for not completing EWC scheduled work has not been addressed.

**CORRECTIVE ACTIONS:**

**Significant CRs:**

No significant CR's (Category A or B) were written against the FAC program for these quarters.

**Open CR CAs:**

No Open CRs as of 12/31/05.  
CR-VTY-2005-02239 was closed out to ER 05-1004 on 12/19/05.

**EQUIPMENT:**

**Open Eng Req:**

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC resistant materials was implemented during RFO25.

04-1315 for Evaluation of Temporary Steam Leak Repair on L.P. Turbine Steam Seal Piping. Removal of Temp Mod, and additional inspections to determine extent of condition were not performed in RFO25 due to schedule conflicts with LP turbine work. Deferred until RFO26. (Ref. VYPPF 7102.01 for W.O. 04-004983-000/010, dated 11/1/05)

**Operator Work Arouds:**

N/A - There are no operator work arouds related to the FAC program.

**Prog Related LCOs:**

There are no LCOs related to the FAC program these quarters.

**PMs Within Due Date:**

N/A - There are no PMs associated with the FAC program.

**Repetitive Failures:**

There are no repetitive equipment related issues for the FAC program these quarters.

**Unanticipated Failures:**

SSH pin hole leaks identified in CR VTY-04-02985. Temporary leak enclosure called. Additional inspections of similar piping incorporated into scope of RFO 25. However deferred until RFO26 due to schedule for LP turbine work.

**Trending Results:**

N/A with respect to equipment.

**Open Work Requests:**

N/A - There are no work requests over 2 yrs old.

**Surveillances Within**

**Due Date:**

N/A No Technical Specification Surveillances under the FAC program were performed in RFO25.

**Significant Parts Issues:**

N/A - There are no parts issues associated with the FAC program this quarter

**Identified Concerns:**

No other identified equipment concerns.

**ORGANIZATION:**

**Staff Qual and Trng:**

The program owner and backup engineer are qualified to perform FAC Program tasks.

3rd Engineer obtained basic FAC training and CHECWORKS SFA training, 2nd Qtr. 2005.

Program owner and backup qualified to ENN Standard FAC Qual Card. ENN-TKESPG042 10/5/05

**Bench Strength:**

The program owner and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in C/S (R. Orner) has FAC related experience and has updated training 2nd Qtr. 2005.

**Program Ownership:**

Site personnel are aware of the Program Owner based results from last SA.

FAC Program ownership to be transferred to Code Programs Group per ENN model. Interviews for new FAC Program Engineer to reside in Code Programs Group started in October 05.

**HU Errors:**

There was one 1 human performance error (HPE) as a result of Program implementation activities for the third quarter of 2005 (CR-VTY-2005-02239 on procedure compliance)

**AP0098 Expectations:**

Continued difficulties in completing program activities on schedule. EPU work is winding down in second qtr. of 2005. FAC Program engineering work has been begun with update of the piping FAC susceptibility review and ENN procedure transition activities. A formal action plan per ENN-MS-S-008 to get program status to Green and address ENN standardization issues was developed and work has begun. Status: 8 of 9 items completed in 2005. Remaining task is in progress. Keep status as White.

**Operating Experience:**

See 2005 RFO Scoping Worksheets for a list of FAC related OE.

**ECs:**

None

**Outage Health:**

**Outage Perf:**

RFO25 in October/November 2005. All planned inspections performed except Nos. 2004-24 to 2005-35. These are located on LP Turbine SSH and SPE lines to determine extent of condition for CR-VTY-2004-02925. These inspections were to be coordinated with removal of Temp Mod 2004-031. Restoration of the Temp Mod was deleted from the outage scope on 10/24/05 as documented on YPPF 7102.01. Access to this piping could not be obtained due to critical path work on the LP turbines. Inspections were deferred to RFO26.

**Outage Preparation:**

RFO25 Outage planning milestones met.

**Generation Health:**

**Generation Health:**

There were no transients or power reductions as a result of a FAC Program issue in Q3 & Q4 2005.

**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion Program (FAC)**

VC

Owner: Jim Fitzpatrick

Phone: 802.451.3086

Controlling Document: PP 7028

Supervisor: Scott Goodwin

Date: **06-Sep-05**  
Quarter: **Second Quarter, 2005**  
Program Color: **White**  
Trend: **Steady**

2004-Q1	2004-Q3	2004-Q4	2005-Q1
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**Current Status Basis:**

The FAC Program has just completed 2nd Qtr. 2005.

Program is white, based on 22 Green, 3 White, and 1 Yellow indicators.

There are no outstanding issues which are not already addressed that may impact the program.

**Current Activities:**

2nd. Qtr. 2005 (4/1/05 to 6/30/05)

WANO Inspection, April 2005

RFO25 Outage Planning & Preparation

RFO25 Outage Scope Challenge Meeting  
5/4/05

The program and ENN procedure transition activities were rescheduled into EWC to start 2nd Qtr. 2005. Activities were started but not completed due to EPU related design changes. This a continued trend from the previous quarter program health reports.

Preparation for July NRC FAC Inspection.

**Significant Accomplishments:**

WANO Inspection Complete - No AFIs for FAC Program

**Actions To Return To Green:**

Ensure that ongoing program tasks which were re-scheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo are in fact performed on or near to schedule. This requires adequate time & personnel be allotted to perform program tasks. A formal action plan per ENN-MS S-008 to get program Green status and address ENN standardization issues was developed in May 2005.

**Exceptions To Grading Criteria:**

NONE

**REGULATORY:**

No FAC Program Related LERs this

quarter.

**INPO Findings:**

No NRC Findings  
No INPO Findings or AFIs.

**GL 91-18 and Op Det:**

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

**Regulatory Compliance:**

The FAC Program currently meets all regulatory requirements.

**New RRs and Code Cases:**

ASME Code Case N-597 was incorporated into R.G 1.147 Rev.13 with new caveats for use. This will affect DP-0072 and transition to ENN-DC-133. WPO has decided to replace ENN-DC-133 with a new engineering Guide ENN-CE-G-001. VY Comments on draft sent to WPO on 5/24/05.

**ADMINISTRATIVE:**

**Procedure, Program Compliance Issues:**

No Program Compliance issues with current Regulations of Codes.

**Budget, Resources:**

2004 and 2005 scheduling of FAC Program per ENN-DC-183 Program Scoping Memo.

FAC Program personnel (resources) were utilized on EPU related design changes and calculations. EWC schedule has Program resources back onto FAC work in 2nd Qtr. 2005.

**Audits:**

WANO inspection April 2005.

An NRC Inspection of the FAC Program for addressing EPU changes to piping and operating conditions is scheduled for July 25, 2005.

**Open Action Items:**

LO-VTYLO-2003-00327 CA 2 due 1/13/06 (two due date extensions)  
LO-VTYLO-2003-00327 CA 6 due 10/03/05 (one due date extension)  
LO-VTYLO-2004-00399 CA 1 due 12/31/05 (one due date extension)  
LO-VTYLO-2003-00327 CA 4 due 2/10/06 (one due date extension)  
LO-VTYLO-2003-00327 CA 5 due 1/15/06 (one due date extension)

LO-VTYLO-2005-00030 CA11 due 10/03/05  
(one due date extension)

**BenchMarking, SelfAssessment:**

Focused Self Assessment October 2003. Ongoing work for Corrective Actions generated from assessment. See LO-CAs (2003-0327) under Open Action Items

**EWC Milestones, New Eng Issues:**

Ongoing program tasks were rescheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo. Continued difficulty in meeting re-projected schedules due to emergent work, EPU, & other unscheduled tasks. A formal action plan per ENN-MS-S-008 was developed in 2nd. Qtr. 2005. Action Plan addresses issues to get program to Green status and ENN standardization.

**Program Concerns:**

Scheduled FAC program activities were started late in quarter due to resources spent on EPU related work. Concern from previous qtr. A formal Action Plan per ENN-MS S-008 was developed to get program Green status and address ENN standardization issues.

**CORRECTIVE ACTIONS:**

**Significant CRs:**

No significant CR's (Category A) were written against the FAC program for this quarter.

**Open CR CAs:**

None for 2nd Qtr. 2005

**EQUIPMENT:**

**Open Eng Req:**

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC Resistant materials. Approved in EWC. Replacement to be implemented in RFO 25

ER 04-1315 for Evaluation of Temporary Steam Leak Repair on L.P. Turbine Steam Seal Piping

**Operator Work Arounds:**

N/A - There are no operator works arounds related to the FAC program.

**Prog Related LCOs:**

There are no LCOs related to the FAC

**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion Program (FAC)**

AC

Owner: Jim Fitzpatrick

Phone: 802.451.3086

Controlling Document: PP 7028

Supervisor: Scott Goodwin

program this qtr.

**PMs Within Due Date:**

N/A - There are no PMs associated with the FAC program.

**Repetitive Failures:**

There are no repetitive equipment related issues for the FAC program this quarter.

**Unanticipated Failures:**

SSH pin hole leaks identified in CR VTY-2004-02985. Temporary leak enclosure installed. Additional inspections of similar piping incorporated into scope of RFO 25.

**Trending Results:**

N/A with respect to equipment.

**Open Work Requests:**

N/A - There are no work requests over 2 yrs old.

**Surveillances Within**

**Due Date:**

Inspections scheduled in the RFO 2004 section scope were completed during RFO 24. No surveillances scheduled for 2nd Qtr. 2005.

**Significant Parts Issues:**

N/A - There are no parts issues associated with the FAC program this quarter

**Identified Concerns:**

No other identified equipment concerns.

**ORGANIZATION**

**Staff Qual and Trng:**

The program owner and Backup engineer are qualified to perform FAC Program tasks.

3rd Engineer obtained basic FAC training and CHECWORKS SFA training, June 6-8.

**Bench Strength:**

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Orner) has FAC related experience and has updated training (June 6-8).

**Program Ownership:**

personnel are aware of the Program owner based results from last SA.

**HU Errors:**

There were no human performance errors (HPE) as a result of Program implementation activities for this quarter.

**AP0098 Expectations:**

Continued difficulties in completing program activities on schedule. EPU work is winding down in second qtr. of 2005. FAC Program engineering work has been begun with update of the piping FAC susceptibility review and ENN procedure transition activities. A formal action plan per ENN-MS S-008 to get program Green status and address ENN standardization issues was developed and work has begun. Status: Progress needs to be monitored. Keep status as White.

**Operating Experience:**

See 2005 RFO Scoping Worksheets for a list of FAC related OE.

**CPIs:**

None

**Outage Health:**

**Outage Perf:**

No outage in 2nd QTR 2005

**Outage Preparation:**

RFO-25 Outage planning milestones met.

**Generation Health:**

**Generation Health:**

There were no transients or power reductions as a result of a FAC Program issue in Q2.

**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion Program (FAC)**

**FAC**

**Owner: Jim Fitzpatrick**

**Phone: 802.451.3086**

**Controlling Document: PP 7028**

**Supervisor: Scott Goodwin**

Date: **10-May-05**  
Quarter: **First Quarter, 2005**  
Program Color: **White**  
Trend: **Improving**

2003-Q4	2004-Q1	2004-Q3	2004-Q4
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**Current Status Basis:**

The FAC Program has just completed 1st Qtr 2005.

Program is white, based on 21 Green, 3 White, and 1 Yellow indicators.

There are no outstanding issues which are not already addressed that may impact the program.

**Current Activities:**

1st Qtr 2005 (1/1/05 to 3/31/05)

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC resistant materials. Replacement to be implemented in RFO 25

J4-1315 for Evaluation of Temporary Steam Leak Repair on L.P. Turbine Steam Seal Piping. Inspection of additional components was added to the 2005 RFO scope to determine the extent of condition on the SSH piping.

Scheduled FAC Program Activities for the 1st quarter 2005 were not completed due to EPU related design changes. This a continued trend from the previous quarter program health report. EPU work scheduled to end early 2nd qtr. 2005. FAC program activities were rescheduled into EWC to start 2nd Qtr. 2005.

**Significant Accomplishments:**

Completed Corrective Actions from CR-VTY-2004-3061 and CR-VTY-2004-3062.

Met Outage Milestones for sub-work order generation.

**Actions To Return To Green:**

Ensure that ongoing program tasks which were re-scheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo are in fact performed on or near to schedule. This requires adequate time & personnel be allotted to perform program tasks. A formal action plan per ENN-MS S-008 to get program Green status and address ENN standardization issues will be developed in the 2nd Qtr. 2005.

**Exceptions To Grading Criteria:**

NONE

**REGULATORY:**

**LERs:**

No FAC Program Related LERs this quarter.

**INPO Findings:**

No NRC Findings  
No INPO Findings or AFIs.

**GL 91-18 and Op Det:**

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

**Regulatory Compliance:**

The FAC Program currently meets all regulatory requirements.

**New RRs and Code Cases:**

ASME Code Case N-597 was incorporated into R.G. 1.147 Rev.13 with new caveats for use. This will affect DP-0072 and transition to ENN-DC-133. WPO has decided to replace ENN-DC-133 with a new engineering Guide ENN-CE-G-xxx. Draft of guide sent out for comment on 3/09/05. Scheduled to have review complete by June 2005.

**ADMINISTRATIVE:**

**Procedure, Program Compliance Issues:**

No Program Compliance issues with current Regulations of Codes.

**Budget, Resources:**

2004 and 2005 scheduling of FAC Program per ENN-DC-183 Program Scoping Memo.

FAC Program personnel (resources) were utilized on EPU related design changes and calculations. EWC schedule has Program resources back onto FAC work in 2nd Qtr. 2005.

**Audits:**

A QA audit was performed in Sept/October 2004. The audit identified two procedure compliance issues related to program documentation and timely completion of activities.

CR VTY-2004-03061 identified that the FAC Inspection Report for the 2004 RFO was not completed within 90 days of plant startup as required per PP-7028. Report

was completed 2/15/05 and CR was closed on 2/16/05.

CR VTY-2004-03062 identified a backlog in inspection records being sent to RIMS per AP-6807. For each refueling outage; Program PP7028 inspection records, reports, memos, and component evaluations were packaged similar to job order files and sent to RIMS. CR was closed on 2/16/05

WANO inspection is scheduled for April 2005.

An NRC inspection of the FAC Program for addressing EPU changes to piping and operating conditions is scheduled for July 25, 2005.

**Open Action Items:**

LO-VTYLO-2003-00327 CA 2 due 6/1/05 (one due date extension)  
LO-VTYLO-2003-00327 CA 3 due 5/15/05 (one due date extension)  
LO-VTYLO-2003-00327 CA 6 due 6/13/05 (one due date extension)  
LO-VTYLO-2004-00399 CA 1 due 12/31/05 (one due date extension)  
LO-VTYLO-2003-00327 CA 4 due 7/1/05  
LO-VTYLO-2003-00327 CA 5 due 7/1/05  
LO-VTYLO-2005-00030 CA11 due 7/31/05

**Benchmarking Self Assessment:**

Focused Self Assessment October 2003. Ongoing work for Corrective Actions generated from assessment See LO-CAs (2003-0327) under Open Action Items

Participated in Focused Self Assessment of PNPS FAC Program per EN-LI-104, January 24-28, 2005.

**EWC Milestones, New Eng Issues:**

Ongoing program tasks were rescheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo. Continued difficulty in meeting re-projected schedules due to emergent work, EPU, & other unscheduled tasks. A formal action plan per ENN-MS-S-008 will be developed in 2nd. Qtr. 2005. Action Plan will address issues to get program to Green status and ENN standardization.

**Program Concerns:**

Scheduled FAC program activities for qtr. were not performed due to resources spent on EPU related work. ( Action Plan: Activities were rescheduled in EWC into 2nd qtr. 2005) Same concern from previous qtr. A formal Action Plan per ENN-MS S-008 will be developed to get program Green status and address ENN



**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion Program (FAC)**

**FAC**

**Owner: Jim Fitzpatrick**

**Phone: 802.451.3086**

**Controlling Document: PP 7028**

**Supervisor: Scott Goodwin**

standardization issues will be developed in the 2nd Qtr. 2005.

**CORRECTIVE ACTIONS:**

**Significant CRs:**

No significant CR's (Category A) were written against the FAC program for this quarter.

**Open CR CAs:**

None

**EQUIPMENT:**

**Open End Req:**

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC Resistant materials. Approved in EWC. Replacement to be implemented in RFO 25

ER 04-1315 for Evaluation of Temporary Steam Leak Repair on L.P. Turbine Steam Seal Piping

**Operator Work Arouds:**

N/A - There are no operator works around related to the FAC program.

**Prog Related LCOs:**

There are no LCOs related to the FAC program this qtr.

**PMs Within Due Date:**

N/A - There are no PMs associated with the FAC program.

**Repetitive Failures:**

There are no repetitive equipment related issues for the FAC program this quarter.

**Unanticipated Failures:**

SSH pin hole leaks identified in CR VTY-2004-02985. Temporary leak enclosure installed. Additional inspections of similar piping incorporated into scope of RFO 25.

**Trending Results:**

N/A with respect to equipment.

**Open Work Requests:**

- There are no work requests over 2 wks.

**Surveillances Within Due Date:**

All inspections scheduled in the RFO 2004 inspection scope were completed during RFO 24. No surveillances scheduled for 1st Qtr. 2005.

**Significant Parts Issues:**

N/A - There are no parts issues associated with the FAC program this quarter

**Identified Concerns:**

No other identified equipment concerns.

**ORGANIZATION:**

**Staff Qual and Trng:**

The program owner and Backup engineer are qualified to perform FAC Program tasks.

**Bench Strength:**

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Omer) has FAC related experience.

**Program Ownership:**

Site personnel are aware of the Program Owner based results from last SA.

**HU Errors:**

There were no human performance errors (HPE) as a result of Program implementation activities for this quarter.

**AP0098 Expectations:**

Continued difficulties in completing program activities on schedule. EPU work is currently scheduled to end early in second qtr. of 2005. FAC Program engineering work has been rescheduled to start in 2nd qtr 2005. FAC related milestones and activities to support RFO25 have been completed per schedule. Completion of corrective actions for CR-VTY-2004-3061 and CR-VTY-2004-3062 have resulted in reducing backlog in program documentation. The situation is improving based on end of EPU work, new EWC schedule, and reduction in documentation backlog. A formal action plan per ENN-MS S-008 to get program Green status and address ENN standardization issues will be developed in the 2nd Qtr. 2005.

Status change from Yellow to White.

**Operating Experience:**

See 2005 RFOscoping worksheet for a list

of FAC related OE.

**CPIs:**

None

**Outage Health:**

**Outage Perf:**

No outage in 1st QTR 2005.

**Outage Preparation:**

RFO-25 Outage planning milestones met.

**Generation Health:**

**Generation Health:**

There were no transients or power reductions as a result of a FAC Program issue in Q1.

**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion Program (FAC)**

**FAC**

Owner: Jim Fitzpatrick

Phone: 802.451.3086

Controlling Document: PP 7028

Supervisor: Scott Goodwin

Date: 18-Jan-05

Quarter: 2004-Q4

Program Color: Yellow

Trend: Declining

2003-Q3 2003-Q4 2004-Q1 2004-Q3

**Current Status Basis:**

The FAC Program has just completed 4th Qtr 2004].

Program is Yellow, based on 17 Green, 2 White, and 5 Yellow indicators.

There are no outstanding issues that may impact the program.

**Current Activities:**

4th Qtr 2004 (10/1/04 to 12/31/04)

Design Engineering Manager approved 2003 Focused Self Assessment Report on 10/28/04. Five new LO CAs were generated to address areas for improvement identified in the SA.

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC resistant materials. Approved in EWC. Replacement to be implemented in RFO 25

ER 04-1315 for Evaluation of Temporary Steam Leak Repair on L.P. Turbine Steam Seal Piping. Inspection of additional components was added to the 2005 RFO scope to determine the extent of condition on the SSH piping.

Scheduled FAC Program Activities for the 4th quarter 2004 were not completed due to emergent work and EPU related design changes. This a continued trend from the previous quarter program health report.

**Significant Accomplishments:**

Approval of Focused Self Assessment Report (LO-VTY-2003-0327 CA1)

**Actions To Return To Green:**

Ensure that ongoing program tasks which were re-scheduled for remainder of 2004 per ENN-DC-183 Program Scope Memo are in fact performed on or near to schedule. This requires adequate time & personnel be allotted to perform program tasks.

**Exceptions To Grading Criteria:**

NONE

**REGULATORY:**

**LERs:**

No FAC Program Related LERs this quarter.

**INPO Findings:**

No NRC Findings  
No INPO Findings or AFIs.

**GL 91-18 and Op Dat:**

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

**Regulatory Compliance:**

The FAC Program currently meets all regulatory requirements.

**New RRs and Code Cases:**

ASME Code Case N-597 was incorporated into R.G 1.147 Rev.13 with new caveats for use. This will affect DP-0072 and transition to ENN-DC-133. WPO controls ENN-DC-133. Revisions are planned for 1st Qtr.2005.

**ADMINISTRATIVE:**

**Procedure, Program**

**Compliance Issues:**

No Program Compliance issues with current Regulations of Codes.

**Budget, Resources:**

2004 and 2005 scheduling of FAC Program per ENN-DC-183 Program Scoping Memo.

FAC Program personnel (resources) were utilized on EPU related design changes and calculations.

**Audits:**

There was one QA audit performed for this quarter. The audit was performed in Sept/October 2004. The audit identified two procedure compliance issues related to program documentation and timely completion of activities.

CR VTY-2004-03061 identified that the FAC Inspection Report for the 2004 RFO was not completed within 90 days of plant startup as required per PP-7028.

CR VTY-2004-03063 identified a backlog in inspection records being sent to RIMS per AP-6807.

An NRC Inspection of the FAC Program for addressing EPU changes to piping and operating conditions is scheduled for 2005.

**Open Action Items:**

LO-VTYLO-2003-00327 CA 2 due 3/14/05  
LO-VTYLO-2003-00327 CA 3 due 3/18/05  
LO-VTYLO-2003-00327 CA 6 due 4/1/05  
LO-VTYLO-2004-00399 CA 1 due 4/1/05  
LO-VTYLO-2003-00327 CA 4 due 7/1/05  
LO-VTYLO-2003-00327 CA 5 due 7/1/05

**Benchmarking**

**Self Assessment:**

Focused SA report for VY FAC Program approved by DE Manager 10/28/04. Did not meet EN-LI-104 SA completion date expectations.

Planned participation if Focused Self Assessment of PNPS FAC Program per EN-LI-104 4rd Qtr. deferred until 1/24/05 at PNPS request of PNPS.

**Administrative Backlog:**

**CORRECTIVE ACTIONS:**

**Significant CRs:**

No significant CR's (Category A) were written against the FAC program for this quarter. Existing VY commitments are equivalent to LO-CAs.

**Open CR CAs:**

CR-VTY-2004-03061 CA2 due 2/04/05  
CR-VTY-2002-02568 CA3 due 3/01/05  
CR-VTY-2004-02985 CA3 due 3/11/05

**EQUIPMENT:**

**Open Eng Req:**

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC Resistant materials. Approved in EWC. Replacement to be implemented in RFO 25

ER 04-1315 for Evaluation of Temporary Steam Leak Repair on L.P. Turbine Steam Seal Piping

**Operator Work Arouds:**

N/A - There are no operator works around related to the FAC program.

**Prog Related LCOs:**

There are no LCOs related to the FAC program this qtr.

**PMs Within Due Date:**



**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion Program (FAC)**

**FAC**

Owner: Jim Fitzpatrick

Phone: 802.451.3086

Controlling Document: PP 7028

Supervisor: Scott Goodwin

N/A - There are no PMs associated with the FAC program.

**Repetitive Failures:**

There are no repetitive equipment related issues for the FAC program this quarter.

**Unanticipated Failures:**

SSH pin hole leaks identified in CR VTY-2004-02985. Temporary leak enclosure installed. Additional inspections of similar piping incorporated into scope of RFO 25.

**Trending Results:**

N/A with respect to equipment.

**Open Work Requests:**

N/A - There are no work requests over 2 yrs old.

**Surveillances Within Due Date:**

All inspections scheduled in the RFO 2004 inspection scope were completed during RFO 24. No surveillances scheduled for 4th QTR 2004.

**Significant Parts Issues:**

N/A - There are no parts issues associated with the FAC program this quarter.

**Identified Concerns:**

No other identified equipment concerns.

**ORGANIZATION:**

**Staff Qual and Trng:**

The program owner and Backup engineer are qualified to perform FAC Program tasks.

**Bench Strength:**

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Orner) has FAC related experience.

**Program Ownership:**

Site personnel are aware of the Program Owner based results from recent SA.

**HU Errors:**

There were 2 reported human performance errors (HPE) as a result of Program implementation activities for this quarter.

R VTY-2004-03061 identified that the FAC inspection Report for the 2004 RFO was not completed within 90 days of plant startup as

required per PP-7028.

CR VTY-2004-03063 identified a backlog in inspection records being sent to RIMS per AP-6807.

**AP0098 Expectations:**

Continued difficulties in completing program activities on schedule.

**Operating Experience:**

See 2005 RFOscoping worksheet for a list of FAC related OE.

In addition, LO-OEN-2004-00272 for the 8/04 Mihama Event was generated. CA3 assigned to VY to review FAC Program & Inspection Efforts for applicability to VY. Inspections of piping at two restriction orifices in the Condensate System were added to the RFO 25 scope.

**GPIs:**

None

**Outage Health:**

**Outage Perf:**

No outage in 4th QTR 2004.

**Outage Preparation:**

RFO-25 Outage Milestones met. Initial outage scope mmp issued 7/7/04. Scope freeze on WO generation met 10/7/04.

**Generation Health:**

**Generation Health:**

There were no transients or power reductions as a result of a FAC Program issue in Q4.

**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion Program (FAC)**

**AC**

**Owner: Jim Fitzpatrick**

**Phone: 802.451.3086**

**Controlling Document: PP 7028**

**Supervisor: Scott Goodwin**

Date: **19-Nov-04**  
Quarter: **2004-Q3**  
Program Color: **White**  
Trend: **Declining**

2003-Q2	2003-Q3	2003-Q4	2004-Q1
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**Current Status Basis:**

Program is -White, based on 16 Green; 3 White; 2 Yellow; and 0 Red

**Current Activities:**

3rd Quarter 2004 (6/16/04 to 9/30/04)

Review and comments on new ENN Standard FAC Program Procedure, ENN-DC-315, and new Gridding Standard, ENN-EP-S-005.

Addressed NRC RAIs relating to FAC for the VY Power Uprate Submittal.

FAC Program coordinator cancelled attendance at June 28 EPRI Chechworks Users Group Meeting due to VY forced outage. Meeting information available on JG web site.

FAC Program coordinator participated in QA Audit of FPL Corporate FAC Inspection Program at Juno Beach FL. July 12 to 16.

FAC program engineers participated in NRC Inspection for EPU affects on FAC program.

Incorporated Design Engineering Manager comments on 2003 Focussed Self Assessment. Returned report to DE Mgr. on 9/1/04.

Scheduled FAC program work activities for 3rd qtr. were deferred due to emergent work; forced outage, NRC inspection, engineering support for intervenor requests for information, and intervenor contentions.

**Significant Accomplishments:**

NRC Inspection

**Actions To Return To Green:**

Ensure that ongoing program tasks which were rescheduled for remainder of 2004 per ENN-DC-183 Program Scope Memo are in fact performed on or near to schedule. This requires adequate time & personnel be allotted to perform program tasks.

Status: There was no improvement in this area for the 3rd quarter of 2004.

**Exceptions To Grading Criteria:**

None

**REGULATORY:**

**LERs:**

No FAC Program Related LERs this quarter.

**INPO Findings:**

No NRC Findings  
No INPO Findings or AFIs.

**GL 91-18 and Op Dat:**

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

**Regulatory Compliance:**

No Regulatory Compliance Issues related to the FAC Program this quarter.

**New RRs and Code Cases:**

ASME Code Case N-597 was incorporated into R.G 1.147. This will affect DP-0072 and transition to ENN-DC-133. WPO controls ENN-DC-133.

**ADMINISTRATIVE:**

**Procedure, Program Compliance Issues:**

There are no LPCs or relief requests required for regulatory or code compliance.

**Budget Resources:**

2004-2005 budget and schedule for FAC Program established through EWC process using ENN-DC-183 Program Scoping Memo.

For 3rd quarter 2004, FAC Program personnel were utilized on EPU related design changes, calculations, audit support, and intervenor issues.

**Audits:**

An NRC Inspection for EPU included questions on affects of FAC on plant piping and equipment. Final evaluation and documentation had not been performed as of the inspection date. No immediate findings/concerns were identified.

**Open Action Items:**

LO-VTYLO-2003-00327 CA1 (2 due date extensions during period)  
LO-VTYLO-2004-00399 CA1 (1 due date

extension during period).

**Benchmarking Self Assessment:**

Incorporated Design Engineering Manager comments on 2003 Focussed Self Assessment. Returned report to DE Mgr. on 9/1/04.

Documentation of Benchmarking performed during FP&L QA Audit, July 12-16, has not been completed.

Planned participation in Focused Self Assessment of PNPS FAC Program per EN-LI-104 4th Qtr. (Dec.13-16,2004)

**Administrative Backlog:**

Procedure changes to PP 7028 (will be resolved by transition to ENN-DC-315)  
Data transmittal(s) to RIMS

**CORRECTIVE ACTIONS:**

**Significant CRs:**

No significant CR's were written against the FAC program for this quarter.

**Open CR CAs:**

CR-VTY-2002-02568 CA3 (due 3/1/05)  
CR-VTY-2004-02985 CA3 (due 3/1/05)

**EQUIPMENT:**

**Open Eng Req:**

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC Resistant materials  
Status: 9/27/04: Recommend transfer to MPRC after approval by the department manager. Project Sponsor: JH Callaghan, SD Goodwin to prepare Funding justification form. 9/30/04 approved by MPRC.

**Operator Work Arouds:**

N/A - There are no operator works around related to the FAC program.

**Prog Related LCOs:**

N/A - There are no LCOs related to the FAC program this qtr.

**PMs Within Due Date:**

N/A - There are no PMs associated with the FAC program.

**Repetitive Failures:**

There are no repetitive equipment related issues for the FAC program this quarter.

**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion Program (FAC)**

**FAC**

**Owner: Jim Fitzpatrick**

**Phone: 802.451.3086**

**Controlling Document: PP 7028**

**Supervisor: Scott Goodwin**

**Unanticipated Failures:**

Non Maintenance Rule. Steam leak identified in LP SSH supply line on 9/24/04. See CR-VTY-2004-02985. Planning for evaluation & repair is in progress as of 9/30/04.

**Trending Results:**

N/A with respect to equipment

**Open Work Requests:**

N/A - There are no work requests over 2 yrs old.

**Surveillances Within:**

**Due Date:**

All inspections scheduled in the RFO 2004 inspection scope were completed during RFO 24. None were scheduled for 3rd qtr. 2004.

**Significant Parts Issues:**

N/A - There are no parts issues associated with the FAC program this quarter.

**Identified Concerns:**

Significant Concern: Scheduled FAC program activities for qtr. were not performed due to resources spent on EPU related work. ( Action Plan: Activities were rescheduled in EWC into 3rd/4th qtr. 2004) Same concern from 4th qtr. 2003. This is an ongoing issue and may require realignment of program resources to insure program activities take priority. No Progress was made in the 3rd Quarter of 2004.

Transition to ENN Standard FAC program, ENN-DC-315, will require revision to ENN-DC-133. Previously scheduled working meetings for revision of ENN-DC-133 for the first quarter of 2004 were not held. WPO controls ENN-DC-133.

**ORGANIZATION:**

**Staff Qual and Trng:**

The program owner and Backup engineer are qualified to perform FAC Program tasks.

**Bench Strength:**

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Orner) has related experience.

**Program Ownership:**

Based on pending results from recent SA the answer is yes.

**HU Errors:**

Completion of the RFO24 FAC Program Inspection Report went past the 90 days from plant start-up as required by PP 7028. Identified by CR-VTY-2004 -03061 on 10/04/04. CR and CAs will be addressed in 4th Qtr program health report.

**AP0098 Expectations:**

RFO 24 Inspection Report was not completed within 90 days from plant start up as required by PP7028. CR VTY-2004-03061 written on 10/4/04, not "prompt" as required by Appendix A of AP0098.

**Operating Experience:**

See 2005 RFO FAC Program Scoping Worksheets for detailed list.

**CPIs:**

None

**Outage Health:**

**Outage Perf:**

Initial RFO 25 outage scope memo issued 7/7/04.

**Outage Preparation:**

Initial RFO 25 outage scope memo issued 7/7/04.

**Generation Health:**

**Generation Health:**

No adverse impact on generation by FAC Program issues or component failures. No transients or power reductions were reported as a result of a FAC Program issue this quarter.

# ENTERGY NORTHEAST, VERMONT-YANKEE ENGINEERING PROGRAM HEALTH Flow-Accelerated Corrosion Program (FAC)

-AC

Owner: Jim Fitzpatrick

Phone: 802.451.3086

Controlling Document: PP 7028

Frequency: Quarterly

Date: 22-Jun-04

Quarter: 2004-Q1

Program Color: White

Trend: Steady

2003-Q1 2003-Q2 2003-Q3 2003-Q4

## Current Status Basis:

Program is White, based on 20 Green; 1 White; 1 Yellow; and 0 Red

## Current Activities:

Attended the EPRI Checkworks Users Group Meeting, January 12-14.

Addressed NRC RAIs relating to FAC for the VY Power Uprate Submittal.

Completed writeup for 2003 Focused Self Assessment for Design Engineering Manager review and approval on 1/30/04.

FAC Program Coordinator participated in JAF FAC Program Self Assessment at WPO 2/9 to 2/13.

viewed draft of Revision 1 changes to ENN-DC-133, for Structural evaluation of worn piping components.

RFO 24 Outage Support for FAC Inspections. Tasks included outage review of Work Order packages, planning, training, data evaluation, turbine crossaround piping visual inspections, and interface with management.

Developed EWC Program Scope Memo (ENN-DC-183) for remainder of 2004 and for 2005.

ENN FAC Working group assigned to an expedited adoption of a new ENN Standard FAC Program. Participated in working group developing a draft of new procedure ENN-DC-315 and new Gridding Standard ENN-EP-S-005 (6/2 to 6/4)

## Significant Accomplishments:

RFO 24

## Actions To Return To Green:

Ensure that ongoing program tasks which were rescheduled for remainder of 2004 per ENN-DC-183 Program Scope Memo are in fact performed on or near to schedule. This requires adequate time & personnel allotted to perform program tasks.

## Exceptions To Grading Criteria:

## REGULATORY:

### LERs:

No FAC Program Related LERs this quarter.

### INPO Findings:

No NRC Findings  
No INPO Findings or AFIs.

### GL 91-18 and Op Det:

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

### Regulatory Compliance:

No Regulatory Compliance issues related to the FAC Program this quarter.

### New RRs and Code Cases:

ASME Code Case N-597 was incorporated into R.G 1.147. This will affect DP-0072 and transition to ENN-DC-133. WPO controls ENN-DC-133.

## ADMINISTRATIVE:

### Procedure, Program Compliance Issues:

There are no procedure/program compliance issues associated with the FAC Program.

### Budget, Resources:

Rating

2003-2004 Budget per supervisor Schedule was set prior to EPU. For remainder of 2004 and 2005 scheduling of FAC Program per ENN-DC-183 Program Scoping Memo.

FAC Program personnel were utilized on EPU related design changes and calculations.

### Audits:

Rating

A NRC Inspection of ISI Program Activities was performed during the beginning of RFO 24. The inspection included an interview of the FAC Program Coordinator on program issues and planned inspections. The inspection report is pending.

### Open Action Items:

LO-VTYLO-2003-00327 (1 extension during period)

### Benchmarking Self-Assessment:

Rating

Participated in Focused Self Assessment of

JAF FAC Program per ENN-LI-104 week of 2/9 to 2/13

Planned benchmarking trip to FP&L in 3rd Qtr. (July 12-16)

Planned participation in Focused Self Assessment of PNPS FAC Program per ENN-LI-104 3rd Qtr. (Aug. 8-13)

### Milestones, new:

Outage support for RFO 24 completed. Ongoing program tasks were rescheduled for remainder of 2004 per ENN-DC-183 Program Scope Memo.

### Engineering Issues, new:

ASME Code Case N-597 was incorporated into R.G 1.147. (DP0072) this will affect transition to ENN-DC-133. Previously planned working group meetings scheduled for 1st qtr 2004 were not held. WPO has control of ENN-DC-133

### Administrative Backlog:

## CORRECTIVE ACTIONS:

### Significant CRs:

No significant CR's were written against the FAC program for this quarter. Existing VY commitments are equivalent to LO-CAS.

### Open CR CAS:

CR-VTY-2002-2568 (5/4/04)

## EQUIPMENT:

### Open Eng Req:

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC Resistant materials

### Operator Work Arouds:

N/A - There are no operator works around related to the FAC program.

### Prog Related LCOs:

N/A - There are no LCOs related to the FAC program this qtr.

### PMs Within Due Date:

N/A - There are no PMs associated with the FAC program.

### Repetitive Failures:

N/A - There are no repetitive equipment related issues for the FAC program this

**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion Program (FAC)**

**FAC**

**Owner: Jim Fitzpatrick**

**Phone: 802.451.3086**

**Controlling Document: PP 7028**

**Frequency: Quarterly**

quarter.

**Unanticipated Failures:** 0

**Trending Results:** Supv. Rati

**Open Work Requests:** 0

N/A - There are no work requests over 2 yrs old.

**Surveillances Within Due Date:** 100

All inspections scheduled in the RFO 2004 inspection scope were completed during RFO 24.

**Significant Parts Issues:** N/A

N/A - There are no parts issues associated with the FAC program this quarter

**Identified Concerns:** 1

Significant Concern: Scheduled FAC program activities for qtr. were not performed due to resources spent on EPU related work. ( Action Plan: Activities were rescheduled in EWC into 3rd/4th qtr. 2004) Same concern from 4th qtr. 2003. This is an ongoing issue and may require realignment of program resources to insure program activities take priority.

**ORGANIZATION:**

**Staff Qual and Trng:** Rating

The program owner and Backup engineer are qualified to perform FAC Program tasks.

**Bench Strength:** 1

The program owner for and backup (T. O'Connor ) are FAC qualified personnel. An additional engineer in M/S (R. Omer) has FAC related experience.

**Program Ownership:** Rating

Based on pending results form recent SA the answer is yes.

**HU Errors:** 0

There were no human performance errors associated with the FAC program this qtr.

**20098 Expectations:** Supv. Rating

**Operating Experience:** Number

See 2004 RFO FAC Program Scoping Worksheets for detailed list.

**CPIs:** Number

None

**Outage Health:**

**Outage Perf:** Rating

**Outage Preparation:** Rating

RFO-24 Outage Milestones met.

**Generation Health:**

**Generation Health:** Rating

No adverse impact on generation by FAC Program issues or component failures. No transients or power reductions were reported as a result of a FAC Program issue this quarter.

<b>FAC</b>	<b>Owner: Jim Fitzpatrick</b>	<b>Phone: 802.451-3086</b>
<b>Controlling Document: PP 7028</b>		<b>Frequency: Quarterly</b>

2002-Q4	2003-Q1
N/A	N/A
2003-Q2	2003-Q3
green	green

## Regulatory Compliance: 0

ASME Code Case N-597 was incorporated into R.G 1.147. (DP0072).  
Transition to ENN-DC-133. Meetings scheduled for 1st qtr 2004 to evaluate

All inspections scheduled in previous outages were performed. RFO 2004 scope is currently being scheduled.



ENTERGY NORTHEAST VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion Program (FAC)

FAC

Owner: Jim Fitzpatrick

Phone: 802.451-3086

Controlling Document: PP 7028

Frequency: Quarterly

Significant Parts Issues: N/A  
N/A

N/A - There are no parts issues associated with the FAC program this quarter

Identified Concerns: Rating: Yellow

Leak in TBV Steam Seal Leakoff piping has elevated the need to complete the update of the small bore piping database (Action Plan: Currently on EWC FAC Program schedule).

Significant Concern: Scheduled FAC program activities for qtr. were not performed due to resources spent on EPU related work. ( Action Plan: Activities were rescheduled in EWC into 1st. qtr. 2004) Same concern from 3rd qtr. 2003.

Potential Issue: Based on experience to date, the transition to ENN procedures is trending toward standardization in name only. The concern is that previous efficiencies at VY will be lost when new ENN procedures modeled on large utility organizations, which require an army to implement, are imposed on the program. (Proposed Action Plan is to participate in transition working groups to control direction of transition or alert management to start hiring.)

ORGANIZATION:

Staff Qual and Trng: Rating: Green

The program owner is qualified to perform FAC Program tasks.

Bench Strength: 2  
Green

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Omer) has FAC related experience.

Program Ownership: Rating: Green

Based on pending results form recent SA the answer is yes.

HU Errors: 0  
Green

There were no human performance errors associated with the FAC program this qtr.

AP0098 Expectations: Rating

Operating Experience: N/A  
N/A

See 2004 RFO FAC Program Scoping Worksheets for detailed list.

GPIS: N/A  
N/A

None

Outage Health:

Outage Perf: Rating: N/A

Outage Preparation: Rating: Green

RFO-24 Outage Milestones met.

Generation Health:

Generation Health: Rating: Green

No adverse impact on generation by FAC Program issues or component failures. No transients or power reductions were reported as a result of a FAC Program issue this quarter.

# **ENTERGY NORTHEAST, VERMONT YANKEE ENGINEERING PROGRAM HEALTH Flow-Accelerated Corrosion Program (FAC)**

**FAC** Owner: Jim FitzPatrick Phone: 802.451-3086  
Controlling Document: PP 7028 Frequency: Quarterly

Date: 18-Nov-03  
Quarter: 2003-Q3  
Program Color: Green  
Trend: Steady  
S

2002-Q3	2002-Q4
N/A	N/A
2003-Q1	2003-Q2
N/A	Green

## **Current Status Basis:**

Current Status: Program is Green, based on 19 Green; 3 White; 0 Yellow, and 0 Red.

Current Status Basis:

Current Program Trend: Steady

## **Current Activities:**

ENN FAC Working group formed (two meetings held). Standardization of ENN FAC Programs is a focus of the group. Each plant is to have a focused self assessment performed. A significant effort was required to develop the standardized evaluation criteria to perform these SAs per new ENN procedure ENN-LI-104.

Qualitative studies & evaluations were performed in support of September EPU submittal.

## **Significant Accomplishments:**

A Focused Self Assessment (per ENN-LI 104) of the VY FAC Program was started on 9/29/03. Results will be incorporated into the 4th Qtr Health Report.

## **REGULATORY:**

LERs: 0  
Green

No FAC Program Related LERs this quarter.

INPO Findings: 0  
Green

No NRC Findings  
No INPO Findings or AFIs.

GL 91-18 and Op. Dat: 0  
Green

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

Regulatory Compliance: 0  
Green

No Regulatory Compliance issues related to the FAC Program this quarter.

New RRs and Code Cases: N/A  
N/A

ASME Code Case N-597 was incorporated into R.G 1.147. This will affect DP-0072 and transition to ENN-DC-133. Meetings scheduled for 4th qtr. to evaluate.

## **ADMINISTRATIVE**

Procedure Program Compliance Issues: 0  
Green

There are no procedure/program compliance issues associated with the FAC Program.

Budget Resources: Rating  
White

2003-2004 Budget per supervisor Schedule was set prior to EPU. For 2003 scheduling of FAC Program activities has been shifted to allow for engineering support off EPU and emergent work. FAC Program personnel were utilized on EPU related design changes and calculations.

Audits: Rating  
Green

There were no Audits performed for this quarter. There are no open issues.

Open Action Items: 4-5 ext.  
Green

LO-VTYLO-2002-00441 (2 extensions.)  
LO-VTYLO-2002-00568 (1 extension)  
LO-VTYLO-2003-00327 (1 extension)  
LO-VTYLO-2002-00528 (1 extension.)  
Note all 5 extensions during qtr. are due to EPU work.

BenchMarking: Rating  
SelfAssessment: Green

S.A. VYM SA 2002-003 on Davis Besse Issues performed in Nov.2002.

Focused Self Assessment of VY FAC Program per ENN-LI-104 started 9/29/03. Significant effort was required to develop evaluation criteria was required by FAC Working Group.

Milestones, new: 0  
N/A

None This Qtr.

Engineering Issues, new: 3  
N/A

ASME Code Case N-597 was incorporated into R.G 1.147. (DP0072).  
Transition to ENN-DC-133. Meetings scheduled for 4th qtr. to evaluate.  
Standardization ENN FAC Programs

## **CORRECTIVE ACTIONS:**

Significant CRs: 0  
Green

No significant CR's were written against the FAC program for this quarter. Existing VY commitments are equivalent to LO-CAs.

Open CR CAs: 1  
N/A

CR-VTY-2002-2568 (5/4/04)

## **EQUIPMENT**

Open Eng Req: N/A  
N/A

N/A; Engineering Requests not yet implemented at Vermont Yankee.

Operator Work Arounds: 0  
Green

N/A - There are no operator works around related to the FAC program.

Prog Related LCOs: 0  
Green

N/A - There are no LCOs related to the FAC program this qtr.

PMs Within Due Date: N/A  
N/A

N/A - There are no PMs associated with the FAC program.

Repetitive Failures: 0  
Green

N/A - There are no repetitive equipment related issues for the FAC program this quarter.

Unanticipated Failures: 1  
White

Turbine Bypass Valve Steam Seal Piping. Additional inspections scheduled for 2004RFO. Also scoping to replace with FAC resistant material.

Trending Results: N/A



**ENTERGY NORTHEAST, VERMONT YANKEE  
ENGINEERING PROGRAM HEALTH  
Flow-Accelerated Corrosion Program (FAC)**

**FAC**

**Owner: Jim FitzPatrick**

**Phone: 802.451-3086**

**Controlling Document: PP 7028**

**Frequency: Quarterly**

**Open Work Requests:** 0  
N/A

N/A - There are no work requests over 2 yrs old.

**Surveillances Within Due Date:** %  
Green

All inspections scheduled in previous outages were performed. RFO 2004 scope is currently being scheduled.

**Significant Parts Issues:** N/A  
N/A

N/A - There are no parts issues associated with the FAC program this quarter

**Identified Concerns:** Rating  
White

Leak in TBV Steam Seal Leakoff piping has elevated the need to complete the update of the small bore piping database (Action Plan: Currently on EWC FAC Program schedule).

Scheduled FAC program activities for qtr. were not performed due to resources spent on EPU related work. ( Action Plan: Activities were rescheduled in EWC into 4th qtr. 2003 & 1st qtr. 2004)

Potential Issue: Based on experience to date, the transition to ENN procedures is trending toward standardization in name only. The concern is that previous efficiencies at VY will be lost when new ENN procedures modeled on large utility organizations, which require an army to implement, are imposed on the program. (Proposed Action Plan is to participate in transition working groups to control direction of transition or alert management to start hiring.)

**ORGANIZATION:**

**Staff Qual and Trng:** Rating  
Green

The program owner is qualified to perform FAC Program tasks.

**Bench Strength:** 2  
Green

The program owner for and backup (T. O'Connor ) are FAC qualified personnel. An additional engineer in M/S (R. Omer) has FAC related experience.

**Program Ownership:** Rating  
Green

Based on pending results form recent SA the answer is yes.

**HU Errors:** 0  
Green

There were no human performance errors associated with the FAC program this qtr.

**AP0098 Expectations:** Rating

**Operating Experience:** N/A  
N/A

See 2004 RFO FAC Program Scoping Worksheets for detailed list.

**CPIs:** N/A  
N/A

None

**Outage Health:**

**Outage Part:** Rating  
N/A

**Outage Preparation:** Rating  
Green

RFO-24 Outage Milestones met.

**Generation Health:**

**Generation Health:** Rating  
Green

No adverse impact on generation by FAC Program issues or component failures. No transients or power reductions were reported as a result of a FAC Program issue this quarter.

Official Transcript of Proceedings ACRST-3397

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards  
Subcommittee on Plant License Renewal

Docket Number: (not applicable)

PROCESS USING ADAMS  
TEMPLATE: ACRS/ACNW-005  
SUNSI REVIEW COMPLETE

Location: Rockville, Maryland

Date: Tuesday, June 5, 2007

Work Order No.: NRC-1602

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TR04

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UNITED STATES NUCLEAR REGULATORY COMMISSION'S  
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

June 5, 2007

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on June 5, 2007, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

This transcript has not been reviewed, corrected and edited and it may contain inaccuracies.

1 UNITED STATES OF AMERICA  
2 NUCLEAR REGULATORY COMMISSION

3 + + + + +

4 ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)  
5 MEETING OF THE SUBCOMMITTEE ON PLANT LICENSE RENEWAL

6 + + + + +

7 TUESDAY,

8 JUNE 5, 2007

9 The meeting was convened in Room T-2B3  
10 of Two White Flint North, 11545 Rockville Pike,  
11 Rockville, Maryland, at 10:30 a.m., Dr. Mario  
12 Bonaca, Chairman, presiding.

13 MEMBERS PRESENT:

14 MARIO BONACA Chair

15 WILLIAM J. SHACK

16 J. SAM ARMJO

17 SAID ABDEL-KHALIK

18 OTTO MAYNARD

19 JOHN BARTON  
20  
21  
22  
23  
24  
25

1 ALSO PRESENT: (CONT. )

2 JAY THAYER

3 SCOTT GOODWIN

4 JOHN HOFFMAN

5 DAVE LACH

6 GARRY YOUNG

7 MIKE STROUD

8 REZA AHRABIA

9 TED IVY

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1 ACRS STAFF PRESENT:

2 MICHAEL JUNGЕ Designated Federal Officer

3  
4 NRC STAFF PRESENT:

5 P.T. KUO

6 MICHAEL MODES

7 RICHARD CONTE

8 JONATHAN ROWLEY

9 LAMBROSE LOIS

10 JIM MEDOFF

11 ROBERT HSU

12 DUK NGUYEN

13  
14 ALSO PRESENT:

15 TED SULLIVAN

16 JOHN DREYFUSS

17 PAUL JOHNSON

18 NORM RADEMACHER

19 DAVE MANNAI

20 ALAN COX

21 MIKE METELL

22 JIM FITZPATRICK

23 TED UNDERKOFFLER

24 LARRY LUKENS

25 JOHN McCANN

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## P-R-O-C-E-E-D-I-N-G-S

10:28 a.m.

CHAIRMAN BONACA: Good morning. The meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. I'm Mario Bonaca, Chairman of the Plant License Renewal Subcommittee for this plant.

ACRS members in attendance are William Shack, Otto Maynard, Said Abdel-Khalik, Sam Armijo, and John Barton. Michael Junge, of the ACRS Staff is the Designated Federal Official for this meeting.

The purpose of this meeting is to review the license renewal application for the Vermont Yankee Nuclear Power Station, the draft SER, and associated documents.

We will hear presentations from representatives of the Office of Nuclear Reactor Regulation, NRR, the Region 1 office, and Entergy Nuclear Operations, Incorporated.

The subcommittee will gather information, analyze relevant issues and facts, and formulate proposed position and action as appropriate for deliberation by the full committee.

Rules of participation in today's meeting were announced as part of the notice of the meeting

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1 previously published in the Federal Register. We have  
2 received no requests for time to make oral statements,  
3 and we have received no written comments from members  
4 of the public regarding today's meeting.

5 A transcript of the meeting is being kept,  
6 and will be made available as stated in the Federal  
7 Register notice. Therefore, we request that  
8 participants in this meeting use the microphones  
9 located throughout the meeting room when addressing  
10 the subcommittee. Participants should first identify  
11 themselves, and speak with sufficient clarity and  
12 volume so that they can be readily heard.

13 We will now proceed with the meeting, and  
14 before I call upon Dr. Kuo, of the Office of Nuclear  
15 Regulation, to begin I would like to make a couple of  
16 general observations regarding this application.

17 The first is really a recurrent theme, I  
18 guess, and the question regarding GALL, and one thing  
19 what we notice is that there is an increasing number  
20 of exceptions being taken on the GALL, and this is not  
21 an issue only for Vermont Yankee. We've seen it  
22 coming, and I have raised a number of questions in the  
23 past regarding whether or not GALL should be updated  
24 to be less descriptive, and to incorporate some of  
25 this that are really not exceptions, they are just

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1 alternatives. For example, in some cases to ASME code  
2 on the report, and to have their views regarding, you  
3 know, how do we reduce the number of exceptions being  
4 taken. I mean, GALL was originally a cooperative  
5 effort between the industry and the staff, to see that  
6 there is, you know, 70 percent of the programs take  
7 exceptions from GALL says something that has to be  
8 looked at.

9 The second issue I would like to raise is  
10 the one of the audit report. The audit report is  
11 growing, and it's becoming almost a duplicate of the  
12 portion of the SER, but it's not written the same way.  
13 So, a reviewer, like the ACRS members, is puzzled by,  
14 you know, what information is there in one that is not  
15 in the other. Typically, there is none, but in some  
16 cases there is. So, you know, is there any way in  
17 which that two things can be meshed together and  
18 become one document only in the future.

19 So, these are the two issues I would like  
20 to raise, and again, the first one that I talked about  
21 may be significant enough to deserve a meeting at some  
22 point in the future, because it's not specific to  
23 Vermont Yankee, it's more generic to GALL.

24 MR. KUO: Thank you, Dr. Bonaca.

25 I'm P.T. Kuo, the Director of the Division

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1 of License Renewal.

2 Your observation is actually very correct,  
3 and very on the point. We have observed this same  
4 phenomena also, and in the past that's why we tried to  
5 update GALL, and in 2005 we updated GALL. The hope  
6 was that we would be able to eliminate many of the  
7 exceptions that we have -- you have been talking  
8 about.

9 And recently, in a couple of the most  
10 recent reviews, we find that, again, there were a lot  
11 of exceptions, more than what we would like to see.

12 So, this is the one thing that we are  
13 working on that. We will be working with the  
14 industry. We will actually bring this very subject to  
15 the industry and see if there's any ways that we can  
16 reduce the number of exceptions.

17 With the number of exceptions we see right  
18 now, it doesn't make sense any more to have the GALL  
19 report there with the program, and then, you know,  
20 everybody is taking exceptions, and then why  
21 there's no reason for the GALL to exist any more.

22 CHAIRMAN BONACA: For example, on the  
23 containment issue, if I remember, there is a statement  
24 that says exceptions are so many that there was no  
25 point in listing them, otherwise it would have been

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1 confusing. Therefore, there is a description of the  
2 problem separate from GALL.

3 So, that, to me, was a clear indication we  
4 had to talk about where GALL is going.

5 MR. KUO: Yes, I fully agree with that  
6 assessment, and like I said we plan to work with the  
7 industry, and at some point we will come back to the  
8 committee and give you a status report on this.

9 As far as the audit report, I think we  
10 have come back to the committee about, I forget how  
11 long ago, about a few months ago. We told you that we  
12 are going to change from writing the 700 or 800 page  
13 report to what we call database.

14 What the database is, really, is something  
15 that when we go to the -- when the audit team goes to  
16 the site and audits the on-site design basis document,  
17 the applicant will create a question and answer  
18 database, and this database is evolving during the  
19 audit, so it's changing. Whenever we have a question,  
20 they have an answer, and that database has got to be  
21 revised.

22 But, at the end of the audit, we expect  
23 the applicant to submit this database, question and  
24 answers, to us, and their information, that becomes a  
25 formal document. Okay.

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1           Then, the staff will take that database  
2 and build on it to actually provide a write-up similar  
3 to SER, basically, providing technical justification  
4 to the database and the status, whether it is still  
5 under discussion, open, or closed.

6           So, we are going to build, if you will, an  
7 audit report on the question and answer database  
8 submitted to us, and then provide the write-up on the  
9 technical justifications, and every time we will  
10 indicate what the status of that is.

11           So, that becomes, actually, the main body  
12 of the future audit report.

13           At the end of audit, okay, when everybody  
14 is ready to close out the audit status, then we will  
15 put a very simple description on top of this database,  
16 and then that becomes the audit report.

17           CHAIRMAN BONACA: Thank you, appreciate the  
18 explanation.

19           MR. KUO: So, that's what we are doing  
20 right now.

21           CHAIRMAN BONACA: Thank you. Okay.

22           So, I'll turn the meeting over to you, Dr.  
23 Kuo, for the Vermont Yankee application.

24           MISS KIMBALL: Well, yes, we have completed  
25 our safety evaluation, and we have an issue there to

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1 report to you. About a month ago, you have it in your  
2 hand, and I believe in that safety evaluation report  
3 we have the four confirmatory items that is,  
4 basically, about the boundary of the non-safety-  
5 related structures over safety-related structures.  
6 Okay. We were -- because of the spatial relationship,  
7 we have asked our regional staff to help us to walk  
8 down the plant, and so that they can have a better  
9 assessment of that.

10 We haven't been able to get input from the  
11 region yet, but this is something that we are going to  
12 have it, so we make it the confirmatory item in the  
13 report. As soon as we get input from the region, we  
14 will be able to hopefully close that out.

15 Recently, it has caught our attention  
16 about a dam, their own dam, and that, the issue, it  
17 was closed in the SER, but we noticed lately that this  
18 dam was owned by Trans-Canada, and because of the  
19 different ownership there is a question who is really  
20 responsible for the management of the dam. Okay. So,  
21 we have some ongoing discussion with the applicant,  
22 and I'm sure today they will address that, too. So  
23 that, we think, is resolved, but we will treat it as  
24 a confirmed item, too, so that is a new item added to  
25 the original SER that you had.

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1 And, that is, really, the review status  
2 right now. Right now I'm turning to the applicant to  
3 make their application, and then the staff  
4 presentation will follow.

5 With that, I turn to the applicant.

6 MR. SULLIVAN: Good morning, I'm Ted  
7 Sullivan, I'm the 2<sup>nd</sup> Vice President for Vermont  
8 Yankee, and I'd like to thank the ACRS for allowing us  
9 to present the license renewal application here today.

10 I'd like to introduce John Dreyfuss. John  
11 is the Director of Nuclear Safety Assurance at Vermont  
12 Yankee, and he'll be lead presenter today, and I'd  
13 like the Vermont team to introduce themselves, and  
14 then I'll turn it directly over to John to make the  
15 presentation.

16 Thank you.

17 MR. RADEMACHER: Norm Rademacher, I'm the  
18 Director of Engineering.

19 MR. MANNAI: Dave Mannai, Entergy Vermont  
20 Yankee Licensing Manager.

21 MR. COX: I'm Alan Cox with the Entergy  
22 License Renewal Team.

23 MR. METELL: Mike Metell, Vermont Yankee  
24 License Renewal Project Manager.

25 MR. FITZPATRICK: Jim Fitzpatrick, Vermont

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1 Yankee Design Engineering & Civil Structural Group.

2 MR. UNDERKOFFLER: Ted Underkoffler, I'm a  
3 Co-Program Engineer, I am the responsible individual  
4 for the Section 11 Containment Inspection Program.

5 MR. LUKENS: Larry Lukens, vermont Yankee  
6 in Programs and Components Engineering Department.  
7 I'm the Supervisor of Code Programs.

8 MR. McCANN: Good morning. My name is John  
9 McCann. I am the Director of Licensing for the Entergy  
10 Fleet.

11 MR. THAYER: I'm Jay Thayer, I'm Vice  
12 President of Operations for Entergy Nuclear. I'm on  
13 loan to the Nuclear Energy Institute.

14 MR. GOODWIN: Good morning. I'm Scott  
15 Goodwin, Entergy Design --

16 CHAIRMAN BONACA: You are going to have to  
17 come to a microphone if we are going to go around the  
18 room.

19 MR. GOODWIN: Good morning. I'm Scott  
20 Goodwin, Entergy Vermont Yankee Design Engineer and  
21 Civil Structural Supervisor.

22 MR. HOFFMAN: Good morning. My name is  
23 John Hoffman. I'm currently retired from Entergy. I  
24 was the previous Site License Renewal Project Manager.

25 MR. LACH: Good morning. My name is Dave

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1 Lach. I'm the Entergy Corporate License Renewal  
2 Services Project Manager for the VY License Renewal  
3 Project.

4 MR. YOUNG: I'm Gary Young with Entergy,  
5 and I'm the Manager of the License Renewal Group for  
6 Entergy.

7 MR. STROUD: My name is Mike Stroud with  
8 the Entergy Corporate Group for License Renewal, and  
9 I am the Electrical Lead for Electrical Programs and  
10 Review.

11 MR. AHRABIA: My name Reza Ahrabia, I'm the  
12 SI, Civil Structural Lead for License Renewal.

13 MR. IVY: And, my name is Ted Ivy, I'm with  
14 the Entergy Corporate License Renewal Services Group.  
15 I'm the Mechanical Lead.

16 MR. JOHNSON: I'm Paul Johnson at Vermont  
17 Yankee. I'm Electrical Design Engineer.

18 MR. DREYFUSS: All right.

19 MEMBER BARTON: I'm glad you left somebody  
20 there behind to run the plant. I was getting a little  
21 nervous about that.

22 MR. DREYFUSS: Gentlemen, good morning,  
23 John Dreyfuss, Director of Nuclear Safety Assurance  
24 for Vermont Yankee. I'm responsible for, among other  
25 things, the Regulatory, Compliance and Licensing

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1 Group. I'm also the Project Sponsor for the License  
2 Renewal Project for Vermont Yankee.

3 Where we are at right now, and we'll talk  
4 about it a little bit as we go through recent plan  
5 performance and current plan status, but we are, as we  
6 speak, turning the moats switch after a refuel outage,  
7 and we are going to plant start up.

8 So, we appreciate being here, thank you  
9 for entertaining us here at the ACRS meeting.

10 I did want to point out a couple of quick  
11 features here. Here's the Connecticut River. Here's  
12 the plant. There's the stack back here. We have the  
13 intake and the discharge. I think what you'll find is  
14 that the plant has been very well maintained over the  
15 years. We will talk about some of the capital  
16 improvements that we have been making to the plant  
17 over the years, in accordance with our long-range  
18 plan, and a big investment by Entergy in the plant  
19 over the last several cycles. We'll talk about that  
20 as well.

21 We've done the introductions.

22 Agenda is, we'll talk a little bit about  
23 the site description, touch on licensing history and  
24 some of the big plant improvements that we have made  
25 recently and over the years. We'll talk about recent

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1 plant performance and the project itself and team  
2 composition. We'll also discuss the cost beneficial  
3 severe accident management alternatives that we  
4 identified during the course of license renewal. None  
5 of them are age related, but they are interesting to  
6 speak about.

7 Additionally, we have a number of  
8 presentation topics we've prepared for you on the  
9 containment integrity, both the dry well and torus  
10 shell, and as P.T. Kuo mentioned, we will also discuss  
11 the Vernon Hydroelectric Station.

12 One thing that we have done is in these  
13 presentations we have put together an awful lot of  
14 detail, and we also have some hyperlinks and back-up  
15 slides. If at any point you want more information, we  
16 can provide that for you. If you have seen enough in  
17 the way of information, please say so, we will move on  
18 to any topic that interests you.

19 And, of course, we'll entertain any  
20 questions that you have during the course of the  
21 presentation here.

22 Site description, the plan is a 125-acre  
23 site on the banks of the Connecticut River. It's a  
24 very lovely site. General Electric was the NSSS  
25 vendor, and Ebasco was the AE and builder of the

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1 plant. It is a BWR, Mark I containment. We'll be  
2 discussing that a bit during the course of the  
3 presentations here today.

4 The plant is now rated at 1912, 1912  
5 megawatts thermal, with a 650 megawatt electric  
6 output.

7 MEMBER BARTON: Is that original, or is  
8 that an upgrade?

9 MR. DREYFUSS: That is, during the past  
10 cycle we implemented a power uprate. We had put the  
11 modifications in over the prior two cycles, and in  
12 March of this year got the license up -- I'm sorry,  
13 2006, got the license to do the 20 percent uprate.

14 MEMBER BARTON: Thank you.

15 MR. DREYFUSS: Very good.

16 The cooling is a hybrid cycle condenser  
17 with forced draft cooling, cooling towers. You saw a  
18 little bit of the cooling towers, we have a better  
19 shot of that later as well in the presentation slides,  
20 and we are currently at a staff of 650 people. That  
21 includes our contractors of supplemental work force.

22 Here are some of the licensing highlights.  
23 The plant did go on line in 1972, in March. The  
24 expiration of the operating license is March 21, 2012.  
25 Thus, we are here.

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1 I did want to point out, in July of 2002  
2 the plant was acquired by Entergy from Vermont Yankee  
3 Nuclear Power Corporation, and that really marked the  
4 beginning of a number of substantial capital upgrades  
5 and major projects, the power uprate project that we  
6 talked about, the 20 percent power uprate, dry fuel  
7 storage on site at the facility, as well as the  
8 License Renewal Project kicked off after Entergy  
9 acquired the plant.

10 I'll go through some of the major plant  
11 improvements that we've had. We did replace core spray  
12 piping back in 1978. We did the full bevy of  
13 modifications to the Mark I containment in the '78 to  
14 '82 time frame, new saddles, the hold downs, the  
15 shortening of the downcomers to alleviate some of the  
16 Mark I containment loading. All of that work was done  
17 during that period of time.

18 In 1986, we replaced our recirc piping  
19 with low carbon steel, 316 low carbon steel.

20 In 1998, we put in our new suction  
21 strainers, resulting as a result of some of the  
22 industry operating experience that was out there. We  
23 also took that opportunity to recoat our torus. We'll  
24 be talking about that a little bit later in the  
25 presentation as well.

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1           2001, we applied noble chemistry for the  
2 first time at the plant, successful application. We  
3 most recently reapplied or put our second application  
4 on in the past refueling outage. Again, a successful  
5 application. And, we've also gone to hydrogen water  
6 chemistry, and, of course, those two in combination  
7 really do provide for the asset protection and IGSCC  
8 mitigation.

9           MEMBER BARTON: What's your hydrogen water  
10 chemistry designed to protect? I mean, how much --  
11 you know, it can vary on the amount of hydrogen  
12 depending on what you are trying to protect in the  
13 core internals. What are you trying to protect?

14           MR. DREYFUSS: We protect the full asset  
15 and the recirc loop as well.

16           MEMBER ARMIJO: How do you monitor that?  
17 Do you have online ECP monitoring, or just do it --

18           MR. RADEMACHER: This is Norm Rademacher.  
19 Yes, we do have an online ECP monitor, and  
20 we just -- as a matter of fact, as a result of this  
21 outage we put in a new one just for ongoing cycling.

22           MEMBER SHACK: What fraction of the cycle  
23 is it operable for?

24           MR. RADEMACHER: We are also investigating  
25 other alternatives to the General Electric supplied

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1 ECP monitor, to improve the reliability.

2 MR. DREYFUSS: We have had them fail  
3 after two months of operation. We have replaced them  
4 as well. We've had them work for quite a while, and  
5 we are working, as Norm said, on doing an upgrade.

6 MEMBER BARTON: What's your success rate  
7 with operation of hydrogen water chemistry as a  
8 system, 95 percent of the time? How much?

9 MR. RADEMACHER: 98 percent.

10 MEMBER BARTON: 98 percent of the time?

11 MR. RADEMACHER: That's correct.

12 MEMBER BARTON: Okay, good.

13 Thank you.

14 MR. ARMIJO: This is maybe a little bit off  
15 base, but have you made any adjustment in your  
16 hydrogen water chemistry when you went from 100  
17 percent to 120 percent --

18 MR. DREYFUSS: Yes.

19 MR. ARMIJO: or did you notice an ECP  
20 change?

21 MR. DREYFUSS: Originally, at the  
22 previous license conditioning, we were running about  
23 3 SCFM and now we are on a 3.5.

24 MR. ARMIJO: Okay.

25 MR. DREYFUSS: Not a substantial change.

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1 This is not necessarily in the slide that  
2 you have in front of you, but we thought it was  
3 worthwhile to mention. We did implement zinc  
4 injection at Vermont Yankee during this past cycle.

5 And, as far as power uprate, equipment  
6 upgrades, I did want to talk some about that. Can we  
7 go to the hyperlink there?

8 MR. ARMIJO: Before you go to that, you  
9 didn't do zinc injection earlier, but you used to have  
10 a brass condenser. Do you still have brass  
11 condensers?

12 MR. DREYFUSS: That's correct. We have  
13 the Admiralty brass condenser, and there is some  
14 natural zinc that we do get as a result of the  
15 condenser that we have.

16 MR. ARMIJO: But, you still keep the  
17 Admiralty brass condenser, or have you changed that?

18 MR. DREYFUSS: We have not changed that,  
19 that's correct.

20 MR. ARMIJO: Okay.

21 MR. RADEMACHER: It is in our long-range  
22 plan after 2010 to change that up.

23 MR. ARMIJO: That would be titanium or --

24 MR. RADEMACHER: We haven't made the  
25 selection of materials at this time.

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1 MR. ARMIJO: Okay.

2 MR. DREYFUSS: I did want to touch on  
3 some of the major equipment changes that we made that  
4 we believe position us well for extended operation and  
5 good plant reliability into that period.

6 We did a change out of the high pressure  
7 turbine, the LP turbines were replaced earlier, prior  
8 to our power uprate, not associated with the power  
9 uprate, so that train is all new.

10 MEMBER BARTON: Was that the rotor cracking  
11 issue?

12 MR. DREYFUSS: No.

13 MEMBER BARTON: Okay.

14 MR. DREYFUSS: No, we had a rotor -- we  
15 had a rotor insulation issue.

16 MEMBER BARTON: Okay.

17 MR. DREYFUSS: And, we did fully  
18 reinsulate the rotor to enable us to stay away from  
19 any kind of thermal sensitivity and vibration on the  
20 power train.

21 MEMBER BARTON: All right.

22 MR. DREYFUSS: We additionally replaced,  
23 rewound the stader. That's all new copper, and  
24 reinsulated the boiler as well.

25 Feedwater heaters, we do have new high

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1 pressure feedwater heaters. We had replaced the LP  
2 heaters in cycles previous to the power uprate  
3 modifications.

4 Switchyard improvements, we, essentially,  
5 replaced the switchyard. We put in lots of new  
6 protective features and redundant protection schemes.  
7 All of the 345, 3-4-5 KV breakers, are new. That was  
8 not driven by uprate, that was driven by our long-  
9 range plan as well.

10 We replaced a number of control systems,  
11 feedwater, level control, the feedwater heater level  
12 control system. The reactor pressure regulator has  
13 gone to digital. We are digital on most of these  
14 control systems, and they are working very fine for  
15 us.

16 And, one of the other big challenges that  
17 we had in going to power uprate was, we went from two  
18 feed pump operation with one in standby, to three feed  
19 pump operation, and we had to make a number of  
20 modifications to be able to address in the event that  
21 we would lose a condensate pump, what would happen to  
22 the feedwater system, and this was an area of interest  
23 during the power uprate proceedings. So, we put in  
24 modifications to provide for auto tripping of a  
25 feedwater pump in the event of a trip of a condensate

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1 pump. Also, an automatic runback of our recirc  
2 system, to maintain power, and additionally, a level  
3 setdown, ultimately, very well analyzed and our goal  
4 was, one, ensure, primarily, that we would maintain  
5 feedwater flow to the reactor vessel, and that we  
6 would not have an inadvertent scram on low level or a  
7 high level trip on the turbine.

8 MEMBER BARTON: On the loss of feedwater  
9 pump you runback or scram?

10 MR. DREYFUSS: Correct, loss of feedwater  
11 pump will do a runback.

12 MEMBER BARTON: Runback.

13 MR. DREYFUSS: Right, and we did an  
14 analysis using some sophisticated modeling.  
15 Ultimately

16 MEMBER ABDEL-KHALIK: What did you do to  
17 the condenser? You didn't say.

18 MR. DREYFUSS: To the condenser, we did  
19 some reinforcement in staking to avert any issues that  
20 we might have with vibration, due to the higher flows.  
21 We did take a look at the condenser this refuel  
22 outage, and we see no issues with the condenser, as a  
23 result of the power uprate.

24 This shows here, up top there is Wayne  
25 Manning, one of our operator, as we did reach the new

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1 power level. The slide below there, or the picture  
2 below, is our Power Ascension Control Center. We did  
3 a deliberate slow power ascension, never going  
4 backwards, but methodical step by step changes in  
5 power, at small increments, analyzed. At the very end  
6 here we did a big integrated plant test, where we  
7 actually did manually trip one of the condensate pumps  
8 and this is the Power Ascension Control Center, the  
9 brain of the power ascension operation, and all of us  
10 sitting around watching the traces and transients.

11 If you are astute, you can see that the  
12 rods remain out, and these are the traces here. Let's  
13 go to that next slide. This was a really nice result.  
14 We had great results from this transient test.  
15 Classic quarter wave dampening on level, you can see  
16 the tripping of a pump here, and the tripping of the  
17 feed pump as far as the changes in feedwater flow, and  
18 this test matched perfectly with our analyzed  
19 projections for the test. So, a testament to, I  
20 think, the engineering staff for the work that they  
21 did in analyzing for this transient as well.

22 MEMBER SHACK: And, your secondary system  
23 piping, has much of that been replaced, or is it still  
24 all carbon steel?

25 MR. DREYFUSS: Go ahead, Norm.

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1 MR. RADEMACHER: A lot of the high usage  
2 areas, drains and such where they go back to the  
3 condenser is chrome-moly. That was the original  
4 design.

5 MEMBER SHACK: Oh, the original design.

6 MR. RADEMACHER: And so, we haven't had to  
7 replace much of that.

8 MR. DREYFUSS: As far as recent plant  
9 performance, current plan performance, current plan  
10 status right now is, we are mode switch to start-up.  
11 We will be withdrawing control rods for start-up from  
12 our refueling outage.

13 Cycle 25, where we did the 20 percent  
14 power uprate, was a 549-day safe, continuous run. We  
15 had shut down for our prior refueling outage, did all  
16 of the maintenance, did some additional power uprate  
17 modifications, started the plant up, and it maintained  
18 -- we maintained it in service during the cycle, as  
19 well as doing the power uprate and power increase  
20 during the wave. So, a good, safe run, and a  
21 testament to the quality of the work that was done.

22 We started our refuel outage on May 12,  
23 2007. Safe shutdown from that outage. We are starting  
24 up as we speak.

25 And, for key outage summary, one thing

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1 that I did want to say, as far as the power uprate  
2 went, we were a full year operation at the extended  
3 uprate level with no challenges to the operators and  
4 good, safe performance of the unit.

5 A couple of key things as far the outage  
6 summary goes, some of the big things that we got done  
7 is, we did replace one of our large feedwater motors,  
8 the size of a walk-in kitchen, I would characterize  
9 it, pretty good size motor. That worked well, and it  
10 was fine. We did replace the last of the 345 KV  
11 breakers that we were seeking to replace. Again, that  
12 was driven by our long-range plan. We have a 15-year  
13 capital plan, and we have a large motor program, we  
14 are replacing and refurbishing motors as we go, and  
15 laying them out in a logical sequence based on  
16 priority.

17 MEMBER BARTON: Does that include your  
18 recirc motors as well?

19 MR. DREYFUSS: We are looking at the  
20 recirc motors as well, and that's a relatively high  
21 priority one for us as well. It's a big job.

22 MEMBER BARTON: Yes.

23 MR. DREYFUSS: The feedwater motor was a  
24 big job, had to cut a hole in the turbine building,  
25 cut a hole in the turbine building floor --

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1 MEMBER BARTON: Roof, yes.

2 MR. DREYFUSS: -- it was a big deal, but  
3 very well done.

4 Service water, we replaced the discharge  
5 valve and check valve on our service water D train,  
6 our delta train of service water. Again, that was work  
7 that we are looking to do. We have the other trains  
8 laid out in our long-range plan that we'll be doing  
9 over the course of the next several years.

10 We did replace a HPCI high pressure  
11 cooling injection turbine exhaust and check valve,  
12 that we had had some history with leak rating. We put  
13 a new check valve in, it's working beautifully.

14 So, some of the highlights from the  
15 outage.

16 MEMBER ABDEL-KHALIK: Now, you've been  
17 operating with a MELLLA power flow limit line?

18 MR. DREYFUSS: We are, we are operating  
19 under the MELLLA operating regime, and we are -- we  
20 did some gamma scanning for this refuel outage in  
21 support of the GE application for the MELLLA+.

22 MEMBER ABDEL-KHALIK: And, your operators  
23 have had no problems operating with MELLLA in terms of  
24 the range of control that they have?

25 MR. DREYFUSS: That's correct. There

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1 have been no problems. Ideally, the MELLA+ will  
2 provide some additional operational flexibility, so  
3 that we have a larger flow window, in particular, end-  
4 of-cycle, so that we don't have to make as many  
5 pattern adjustments to the --

6 CHAIRMAN BONACA: You say a larger flow  
7 window, I mean, you have some flow window now?

8 MR. DREYFUSS: Yes.

9 CHAIRMAN BONACA: With the MELLA?

10 MR. MANNAL: Yes, this is Dave Mannal, we  
11 have about a 4 to 5 percent flow window. It's a  
12 little bit larger than Brunswick's. We did some  
13 industry comparisons with them when we were going to  
14 implement uprate, and I'm pleased to report that over  
15 the last cycle we had a number of rod adjustments  
16 toward the end of the cycle, you know, as is typical,  
17 but not having MELLA+ at a full EPU condition we did  
18 have to do more rod adjustments, but they are all done  
19 safely with excellent focus on reactivity management  
20 and performance. We had no issues as a result of  
21 that.

22 MEMBER ABDEL-KHALIK: And, you can enter  
23 into higher than 100 percent flow range?

24 MR. MANNAL: Yes, we implemented increased  
25 core flow back in late '99, early 2000 time frame, and

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1 we went -- you know, we had the full 107 percent  
2 increase core flow. As you implement power uprate you  
3 lose some of that margin, so we went from 107 percent  
4 down to about 104.5, so our flow window is from 99  
5 percent to, roughly, 104.5 percent flow, so we had a  
6 little bit more margin than one of the Brunswick  
7 units.

8 MEMBER ABDEL-KHALIK: Thank you.

9 MR. DREYFUSS: As far as an overall  
10 summary, excellent plant material condition. We did  
11 do a lot of looking as a result of a power uprate and  
12 the changes that we had made, and we found the plant  
13 to be in excellent health. We'll talk a little bit  
14 more about that.

15 We did not identify any significant  
16 equipment issues, routine items, routine added out of  
17 scope, and well managed and addressed. No generic  
18 issues.

19 Outage items of interest, a lot of  
20 interest from everybody on the steam dryer and its  
21 performance, as well as the performance of flow  
22 accelerated corrosion under the uprate power levels.  
23 I'd like to talk a little bit about both of those  
24 topics as well.

25 MEMBER MAYNARD: You said you are going to

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1 talk more about your first bullet there, excellent  
2 plant material condition?

3 MR. DREYFUSS: Yes, sir.

4 MEMBER MAYNARD: Okay, because that's an  
5 easy -- that's a statement to make, but it doesn't  
6 really give me a feel. You obviously have some issues  
7 and some things that you are dealing with, I'd like to  
8 get a feel for kind of what level of items that you do  
9 have on your list of things to do.

10 MR. DREYFUSS: All right, very good,  
11 thank you.

12 As far as the steam dryer went, during  
13 start up from the last refuel outage we did do  
14 extensive monitoring of the steam dryer to validate  
15 that we are going to remain within the low profile,  
16 code low profiles, and we did do that.

17 But also, during the course of the cycle  
18 we did online monitoring to a high degree.  
19 Additionally, during this last outage, lots of  
20 interest in terms of the steam dryer condition as we  
21 pulled it out of the vessel.

22 So, from an online monitoring standpoint,  
23 we have been monitoring, we saw no changes in reactor  
24 water level that we couldn't explain. Similarly, steam  
25 dome pressure, no changes there that would prompt us

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1 or kick us into any off-normal procedure that we have  
2 for actual steam dryer issues.

3 Additionally, we do monitor moisture  
4 carryover, and we had no unexplained changes with  
5 moisture carryover. It tracked as predicted, with  
6 changes in power or changes in rod sequences, which,  
7 again, those were all anticipated.

8 MEMBER ABDEL-KHALIK: How is that measured?

9 MR. DREYFUSS: We use -- Norm, can you  
10 speak to this?

11 MR. RADEMACHER: Sure. We use sodium-24  
12 testing. The chemistry performs the testing, and use  
13 a radioactive sample and verify. And, they do on a  
14 weekly basis, and we monitor statistically and see if  
15 there's any statistic changes, statistically unusual  
16 changes, every week.

17 And, the performance of that has been  
18 you could see the change with our uprate, as we  
19 increased steam flow you get more carryover, but then  
20 it stays relatively constant through the rest of the  
21 year for the cycle.

22 MR. DREYFUSS: It probably averages about  
23 .12 percent.

24 MEMBER ABDEL-KHALIK: And, the uncertainty  
25 in that is how much?

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1 MR. RADEMACHER: I don't know the answer to  
2 that question.

3 MR. MANNAL: We'll get that information and  
4 get back to you.

5 MR. DREYFUSS: It's very predictable.  
6 We'll get the numbers on the uncertainty for you.

7 For outage monitoring as well, we did take  
8 a look and found that there were no fatigue  
9 indications that have been seen elsewhere in the  
10 industry. I happened to be at one facility when they  
11 removed the dryer from the reactor vessel, and there  
12 were obvious flaws in that steam dryer, in particular,  
13 some of the areas where reinforcement and  
14 strengthening modifications were made. We took a look  
15 at all of those areas, and the steam dryer looks  
16 there were no indications, and the steam dryer is in  
17 very good health.

18 MEMBER BARTON: Are there any cracks at all  
19 in your steam dryer?

20 MR. DREYFUSS: There were some  
21 indications that we identified as well. We'll talk a  
22 little bit about that. We characterized them as IGSCC  
23 as well --

24 MEMBER BARTON: Okay.

25 MR. DREYFUSS: -- and dispositioned them

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1 with General Electric as use as is. I'll explain some  
2 of those as well as we go forward.

3 MEMBER BARTON: All right, thank you.

4 MR. DREYFUSS: Go to the hyperlink here.  
5 This is a shot of the steam dryer here, and we did  
6 find these are the lifting lugs for the steam  
7 dryer. We found that on a tap weld on two of these  
8 lifting lugs, there's a structural weld underneath  
9 here, that was fine, but the tack weld, that's,  
10 essentially, anti-rotation for the lifting lugs, we  
11 did find a couple of small indications there, and they  
12 may be service-induced from lifting, lifting the  
13 dryer.

14 Where we did find IGSCC is, this shows  
15 here, we have two steam dams, and they are about half  
16 an inch wide, 12 feet long, six inches high, and  
17 during the visual inspection, we did very high-quality  
18 visual inspections of this outage as well as last  
19 outage, we saw three indications right along one edge  
20 of the steam dam. They didn't turn the corner  
21 whatsoever, and they look like classic IGSCC-type  
22 indications, dispositioned as use as is. We concurred  
23 with that in our Civil Structural Group, and we will  
24 inspect them next outage.

25 CHAIRMAN BONACA: You didn't see them in

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1 the previous outage?

2 MR. DREYFUSS: We did not see them in the  
3 previous outage.

4 CHAIRMAN BONACA: So, this is indications  
5 that developed over this period of operation.

6 MR. DREYFUSS: That's correct. What we  
7 had done, in 2004, two cycles ago, is we did do some  
8 strengthening modifications here, some weld build up  
9 at this particular area, as well as putting in a  
10 couple of gussets along the length of the steam dam to  
11 improve its strength, and we found that in the heat  
12 affected zone, where we did that work, that's where  
13 the IGSCC showed up.

14 MR. ARMIJO: So, you believe it's residual  
15 stress from your welding that caused the cracking to  
16 initiate there?

17 MR. DREYFUSS: Yes, sir.

18 MR. ARMIJO: Do you have any micro  
19 structural confirmation that it was IGSCC and not  
20 something else?

21 MR. DREYFUSS: No.

22 MR. ARMIJO: So, it's just -- is there  
23 water up there? How can you have a cracking in a  
24 steam dryer? Is there liquid bays up there?

25 MR. MANNAI: A fraction of a percent.

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1 MR. LUKENS: It's very low moisture  
2 content at that part of the dryer.

3 MR. ARMIJO: But, there was no  
4 metallographic sample taken to verify its  
5 intergranulars?

6 MR. DREYFUSS: That is correct.

7 MR. ARMIJO: So, it's an indication, and  
8 you concluded with G.E. that it was IGSCC.

9 MR. DREYFUSS: Right, and we will again  
10 look at it next outage to confirm that.

11 MEMBER MAYNARD: Can you explain to me what  
12 you mean by a very high-quality visual inspection?

13 MR. DREYFUSS: Yes, the standard that we  
14 used was G.E. SIL, Service Information Letter 644  
15 requires visual examination. The technology that was  
16 used, the cameras that were used, the speed at which  
17 the cameras moved, the clarity of the water was very  
18 high as well.

19 MR. RADEMACHER: And the lighting.

20 MR. DREYFUSS: And the lighting was very  
21 good.

22 MR. RADEMACHER: It was almost EVT -- met  
23 EVT standards, the enhanced visual requirements.

24 MEMBER SHACK: Now, how do you disposition  
25 this curve crack? You know, what's the process?

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1 What's the acceptance criteria for the dispositioning?

2 MR. RADEMACHER: General Electric evaluates  
3 it. Well, first off, just to remind you, this is on  
4 the end of the steam dam, it's a ½ inch wide, just on  
5 the face of the steam dam.

6 Then they evaluate the condition, where it  
7 is, and whether it impacts the structural capability  
8 of the steam dryer, and then they provide a response  
9 to us that is reviewed by our structural folks to  
10 verify that it's acceptable.

11 And --

12 Larry, do you have anything to add to  
13 that?

14 MR. LUKENS: This is Larry Lukens.

15 We spent a lot of time on the phone with  
16 General Electric, both their metallurgist and their  
17 analysis folks, on this particular set of indications,  
18 and the cracks are consistent with IGSCC. The history  
19 on this particular spot in the dryer is that in 2004  
20 there were a number of welds that were put on because  
21 of cracks found in structural parts in the vicinity of  
22 that steam dam.

23 This particular spot in the steam dam is  
24 not a structural part of the steam dam. It's about a  
25 3-inch high piece of this 6-inch stainless plate, and

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1 these cracks are characteristic of stress relief.  
2 And, in 2004, when the original indications in these  
3 areas -- this area was identified, there was a lot of  
4 discussion in that analysis about the stress induced  
5 by the welding, by the original manufacturing process.

6 There are four symmetrical locations to  
7 this specific spot, and only one of the four has these  
8 indications.

9 MR. ARMIJO: So, G.E. dispositioned that by  
10 saying, and correct me if I'm not saying what they  
11 told you, but these cracks were caused by residual  
12 fabrication stresses caused by the welding.

13 MR. LUKENS: That's correct.

14 MR. ARMIJO: And, they must have assessed  
15 that these cracks wouldn't propagate and leave you  
16 with a loose part.

17 MR. LUKENS: That was our big concern, yes.

18 MR. ARMIJO: Okay, and that 's been reviewed  
19 with the staff.

20 MR. LUKENS: No, the staff --

21 MR. DREYFUSS: Well, we did do a -- we  
22 had a telecon with Tom Scarborough and a number of the  
23 consultants that were involved in the steam dryer  
24 work, as a courtesy call, and did explain to them what  
25 we saw and what we had identified as well.

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1 MR. RADEMACHER: And, in addition, we  
2 forwarded our detailed report to the staff for their  
3 review, as part of our license conditions, after each  
4 inspection of the dryer wall, for the next -- this  
5 cycle, as well as the next two refueling cycles, we'll  
6 be continuing to monitor the steam dryer, and we'll  
7 prepare a report for the staff for their review.

8 MR. LUKENS: That's a 60-day report.

9 MR. MANNAI: Yes, this is Dave Mannai. I  
10 think it's worth noting, we had set up that courtesy  
11 teleconference with the NRC staff ahead of time, even  
12 before we noted these indications, and we discussed  
13 those indications fully with the staff at that  
14 telecon, and much of the questions that you are asking  
15 now were similar to the questions they asked, and  
16 staff, I believe, was satisfied at the end of that  
17 teleconference. We owed them the formal reports in  
18 accordance with our license condition, 60-day report.

19 MR. DREYFUSS: And, some of the industry  
20 operating experience that we had followed is, there  
21 were substantial flaws here along the lower plate,  
22 along the gussets and shoes, as well as the gussets  
23 pulling away from the actual base plate here. Again,  
24 we looked at all of those areas, all of the preemptive  
25 strengthening modifications that we had done, and

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1 found them to be in good order, no indications there.

2 MR. RADEMACHER: We performed over 460  
3 inspections, both inside and out, and there was no  
4 change in any of the previously identified  
5 indications, and just the new ones that we have  
6 mentioned during our conversation here today.

7 MR. DREYFUSS: Any other questions on the  
8 steam dryer?

9 CHAIRMAN BONACA: Just the question I had  
10 was, you will inspect again at the end of the new  
11 cycle, and for how long do you plan to do inspections?

12 MR. DREYFUSS: We will follow the SIL-644  
13 guidance. However, we did have a license condition  
14 that, rather than every other outage that we would do  
15 three successive --

16 CHAIRMAN BONACA: Yes.

17 MR. DREYFUSS: -- full inspections of the  
18 susceptible, accessible welds. So, this outage and  
19 the next two, we will also do the same type of high-  
20 quality visual inspection.

21 CHAIRMAN BONACA: So, the dispositioning  
22 was, essentially, for a cycle length, or a disposition  
23 that's acceptable for a cycle of operation.

24 MR. DREYFUSS: That's correct.

25 CHAIRMAN BONACA: And, they will be

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1 inspected again.

2 MR. DREYFUSS: Inspect again next cycle,  
3 correct.

4 CHAIRMAN BONACA: Thank you.

5 MR. RADEMACHER: In addition now, as part  
6 of license renewal, we have an ongoing commitment to  
7 meet SIL-644 for the license extension period.

8 MEMBER SHACK: And, it is sort of a rock in  
9 a hard place. Every strengthening operation you make  
10 to protect against fatigue just gives you a new ISSC  
11 location.

12 MR. DREYFUSS: That was one of the  
13 concerns that we had, in terms of the modeling that we  
14 did on the steam dryer, to make sure that we had mesh  
15 sizes small enough to really get a good understanding  
16 of what the stresses were at those key locations.  
17 That did prove to have been accurate, and we don't see  
18 any indications.

19 MEMBER SHACK: Now, the fluids is up here  
20 low enough, you don't have to worry about helium in  
21 the stainless steel?

22 MR. DREYFUSS: Right, yes.

23 MEMBER ABDEL-KHALIK: Was the steam  
24 pressure monitored during the power uprate to detect  
25 any sort of high-frequency variations in steam

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1 pressure?

2 MR. DREYFUSS: Yes, we had highly  
3 instrumented both the steam lines, feedwater lines as  
4 well, and looked at steam dome pressure, and we  
5 monitored any fluctuations there.

6 What we had learned from the industry is  
7 that there were some signals, acoustic signals, that  
8 were being brought from the main steam lines back to  
9 the steam dryer, that's what we monitored.

10 MEMBER ABDEL-KHALIK: And, what were the  
11 results of those monitoring activities?

12 MR. DREYFUSS: We stayed well within the  
13 loads. We never -- it went as we predicted, and did  
14 not approach the ASME loads.

15 MEMBER ABDEL-KHALIK: And, what were the  
16 dominant frequencies?

17 MR. DREYFUSS: We had a frequency at 137  
18 Hertz, and another one -- and we'll give you the exact  
19 numbers, but a little bit -- I think it was 148, 148  
20 Hertz, and they coincided with the SRB branch line  
21 connections off the main steam lines. We had  
22 predicted we would see a spike there, we did see it  
23 there, it grew and then mitigated, and stayed within  
24 the limits.

25 MEMBER ABDEL-KHALIK: Thank you.

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1 MR. DREYFUSS: Okay. Flow accelerated  
2 corrosion, this was another area that we paid  
3 particular attention to under the uprate conditions.  
4 We did increase the number of FAC inspections by 50  
5 percent from what we typically do during outages. We  
6 did do 63 inspections overall. They were satisfactory  
7 and, in fact, they were consistent with your  
8 analytical predictions that we use in our modeling for  
9 FAC.

10 One area that, Jim, maybe you can talk  
11 about, the cross-around piping inspection that we did.  
12 It's one of the susceptible areas.

13 MR. FITZPATRICK: We've got one remaining  
14 carbon steel cross-around. Jim Fitzpatrick. It's the  
15 only thing left in the system that is still  
16 susceptible, so we use that as an indicator, and we've  
17 been doing visual inspections of that almost every  
18 outage. And, it's, essentially, the same condition it  
19 was in 1996, even with the power uprate.

20 We have visual marks on the inside, and  
21 they are still there after this cycle.

22 MEMBER SHACK: Okay, that's how you do the  
23 visual, it's still there.

24 MR. FITZPATRICK: Well, we did UTs, and we  
25 have a mat on the inside, and you go inside the pipe

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1 and see if it's still there.

2 MEMBER SHACK: There's no wall thinning.

3 MR. FITZPATRICK: No, and that's  
4 surprising.

5 MR. LUKENS: This is Larry Lukens, maybe,  
6 maybe the gentleman didn't completely understand what  
7 you said, there were marks -- marks we put on the  
8 inside --

9 MR. FITZPATRICK: Yes.

10 MR. LUKENS: to make sure that we  
11 understood

12 MEMBER SHACK: I was sort of wondering how  
13 you were going to do the visual, you know.

14 MR. ARMIJO: Poke in your head.

15 MR. LUKENS: Actually crawl down the pipe.

16 MEMBER SHACK: No, but I mean, you have  
17 marks, and if they are still there that's an  
18 indication you are not losing metal, yes.

19 MEMBER MAYNARD: The 50 percent increase in  
20 number of FAC inspections, is that just the number of  
21 inspections, or did you also increase number of  
22 locations that you are looking at?

23 MR. DREYFUSS: Jim?

24 MR. FITZPATRICK: A mixture of both. We do  
25 repeat inspections. We do some new areas, try to mix

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1 it up, try to add more areas on the same system, look  
2 at the models, get more data for the check-works  
3 models we are using.

4 MR. ARMIJO: Now you used you have  
5 chrome-moly most here.

6 MR. FITZPATRICK: In the extraction steam  
7 system it's all chrome-moly. The heated drain  
8 systems, everything downstream of the local control  
9 valves are chrome-moly or stainless, except for the  
10 lowest load pressure here.

11 MEMBER SHACK: Do you have a feel for the  
12 amount of margin you have with this material compared  
13 to the carbon steel, as far as FAC resistance?

14 MR. FITZPATRICK: EPRI publishes 34 times  
15 more resistant than the carbon.

16 MEMBER SHACK: Order of magnitude at least,  
17 huh?

18 MR. FITZPATRICK: Well, we are not seeing -  
19 - we've done some monitoring in the past 15 years on  
20 the chrome-moly and haven't seen anywhere at all.

21 MEMBER SHACK: And, this is 2-1/4 chrome-1-  
22 moly or what?

23 MR. FITZPATRICK: Some 2-1/4, some 1-1/4,  
24 EPRI rec -- even if you have a carbon steel that's got  
25 more than 1 percent it works

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1 CHAIRMAN BONACA: Going back to the 50  
2 percent increase, what was the criteria used? I mean,  
3 you looked for still susceptible locations, right?

4 MR. DREYFUSS: Go ahead, Jim.

5 MR. FITZPATRICK: Jim Fitzpatrick.

6 Just for planning, going to the power  
7 uprate, we had pretty good confidence in what was  
8 going on prior to power uprate, and we figured we'd do  
9 50 percent more inspections to get more data, just to  
10 get it back into the check-works models, and then at  
11 the end of the three cycles we'll be assessing where  
12 to go from there.

13 We've been on a trend of small in order  
14 inspections over time, and most of the industry is,  
15 too.

16 MR. DREYFUSS: Okay, and again, we'll  
17 continue to do the increased scope of these  
18 inspections for two more cycles.

19 Now, moving on to the license renewal  
20 project itself. As you have heard from introductions,  
21 we have a multi-discipline team, a good blend of  
22 people from both our Corporate staff, as well as at  
23 the site. At the site, we have personnel, not just  
24 from the key engineering programs, programs and  
25 components and system engineering, design engineering,

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1 we also had operations, maintenance and other groups  
2 participate, so that we would get that synergy and  
3 make sure everybody sees what's coming here with  
4 license renewal.

5 We did, as far as the Revision 1 to the  
6 Standard Review Plan in GALL, it's noteworthy that  
7 both Pilgrim and VY were the first to go that route,  
8 and we are going to talk more about GALL exceptions.  
9 I know you are interested in that, but general overall  
10 -- over-arching philosophy on the GALL is that we  
11 comply with the GALL.

12 There were a number of areas where there  
13 I'd characterize them as technical exceptions for  
14 the GALL that we needed to take, but we were  
15 conservative in the development of the GALL, and I  
16 think you'll find that these are relatively minor  
17 exceptions, and we'll speak to them in detail as well.

18 Of course, we incorporated industry  
19 lessons learned, both at Pilgrim and other fleet  
20 plants that have undergone license renewal, and others  
21 in the industry.

22 As far as the exception types, we have  
23 overall 30 exceptions to the GALL. As far as the  
24 types of exceptions, you know, for example, if we were  
25 committed to a different version of an ASME code, we

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1 did take exception to the GALL. So, we've broken down  
2 the exceptions that we took into six categories that  
3 we'll describe to you, and I'd like to ask Alan Cox to  
4 brief you on that.

5 MR. COX: These six categories -- this is  
6 Alan Cox -- the six categories was our -- to try to  
7 characterize these exceptions, and you can draw the  
8 lines in different places, they are somewhat  
9 arbitrary, I guess, and there's some overlap between  
10 them. So, there's not a real clear-cut line.

11 The first category we've got there is  
12 where an activity is not applicable to the plant  
13 design. That was pretty straightforward. We may have  
14 -- I think we took an exception to metal enclosed bus  
15 program, where it talked about insulation between  
16 phases, we didn't have insulation between phases. In  
17 our bus, we had insulation or insulators that  
18 supported the bus, but we didn't have any insulation  
19 between phases.

20 So, we took, I guess, an overall  
21 philosophy on these exceptions, we took a pretty  
22 conservative or a literal interpretation of what was  
23 in GALL. If it said do an inspection, we did have an  
24 inspection, we tended to call that out as an  
25 exception. I think if you compare applications from

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1 plant to plant you'll see that there's different  
2 degrees of that, there's different levels of  
3 conservatism or how literal you take things, so you'll  
4 see differences in numbers probably because of those  
5 factors.

6 The second category we've got there is an  
7 alternative that's consistent with approved methods.  
8 I guess one of the other philosophies that we took  
9 was, if we had a -- as you know, GALL says that that's  
10 one way of doing things, if we had an existing plant  
11 program that had proven within the, you know, the  
12 circumstances of our plant, our people, our training  
13 programs, if that existing program had proven  
14 effective over the years in dealing with that aging  
15 effect, we didn't make the change in the program just  
16 to say that we were consistent with GALL. We felt like  
17 it was more important to use what's already in place  
18 and what's establish and proven for our plant, for our  
19 circumstances.

20 The third category is programs based on  
21 different code --

22 MEMBER MAYNARD: Excuse me, alternative,  
23 consistent with approved methods, from what I  
24 understood you to say, I'm not sure what the approved  
25 methods are. Is it approved method just because it

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1 has worked for you, or is it other things in the  
2 regulations that --

3 MR. COX: In some cases it's -- the most  
4 obvious thing that comes to mind is the BWR VIP  
5 program. A lot of times you have specifics there that  
6 are -- maybe we've got an approved exception to the  
7 BWR VIP program because of plant unique circumstances,  
8 and we would take that approach.

9 MR. DREYFUSS: You know, Alan, we have an  
10 example that we could go to here.

11 MR. COX: Right.

12 This is one that dealt with the frequency,  
13 and we had approval of the Generic Letter 89-13, to do  
14 things at a refueling frequency, and I think the GALL  
15 report may have been more specific than that, it may  
16 have said annually. In some cases it was not  
17 practical to do it annually, you had the access to the  
18 system, you had plans to do things during refueling  
19 outages.

20 MEMBER BARTON: Your refueling outages are  
21 how often?

22 MR. COX: Eighteen months.

23 MEMBER BARTON: Eighteen months?

24 MR. COX: Right.

25 MEMBER BARTON: Okay.

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1 MR. COX: That's an example of that  
2 category. Again, there are others. There was, oh,  
3 seven or eight examples I think that we had in that  
4 category.

5 The third one, different ASME code  
6 edition, that's pretty straightforward. There's been  
7 a lot of discussion about that. There's was a handful  
8 of things that fell in that category.

9 Again, this category met the equal to or  
10 better than the NUREG 1801 method, that's a little bit  
11 of, you know, the second category that we talked about  
12 earlier is a little bit of the same thing, but we've  
13 got an example of that -- can you click on the example  
14 there?

15 MR. DREYFUSS: Yes, let's look at that.

16 MR. COX: The GALL analysis program, the  
17 GALL program, you know, again, was a program that was  
18 developed off of somebody -- some specific plant that  
19 was reviewed and accepted. Well, it turns out that  
20 that particular plant program had flashpoint testing  
21 in there. We have a practice at vy to do a fuel  
22 dilution test, which is considered to be a better  
23 indicator of the contamination of the lube oil with  
24 fuel oil than a flashpoint test. So again, it's an  
25 alternative that's equally effective, if not better,

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1 than what was in the NUREG, and it's a fairly minor  
2 thing, it took pretty little interpretation and  
3 decided that that was something we needed to flag as  
4 an exception.

5 MR. DREYFUSS: Okay

6 MR. COX: The experience justifies  
7 exception.

8 MEMBER BARTON: That's a scary one

9 MR. COX: It really kind of ties back in to  
10 the philosophy that we were talking about earlier,  
11 where you've got an established program that's been  
12 proven effective under the plant specific  
13 circumstances that it's applicable to, and just go and  
14 click on the example of that, if you will.

15 Diesel fuel additives is specified in the  
16 particular GALL program. At VY, there's a long  
17 history of not requiring any additives beyond those  
18 which are provided as part of the manufacturing  
19 process by the fuel vendor, and we've had very good  
20 operating experience with the existing process. We  
21 didn't feel like it was appropriate to change that.

22 MEMBER BARTON: How about how about  
23 containment leak rate tests ten to 15 years, where did  
24 that one come from?

25 MR. UNDERKOFFLER: We presently Ted

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1 Underkoffler -- we presently test containment on a  
2 ten-year basis.

3 MEMBER BARTON: Right.

4 MR. UNDERKOFFLER: We are right in a five-  
5 year extension right now.

6 MEMBER BARTON: About what?

7 MR. UNDERKOFFLER: On the analysis of the  
8 uprate analysis. We did the extension for five years.

9 MEMBER BARTON: One time?

10 MR. UNDERKOFFLER: One time only, and we'll  
11 be doing our integrated test in 2010.

12 MR. DREYFUSS: Go ahead.

13 MR. COX: I'd say there's only a couple  
14 exceptions that we considered in that fifth category.

15 The final one is the NUREG 1801 method is  
16 not feasible, and again, this examples that we had in  
17 that category were all related to the BWR VIP program,  
18 where the VIP program recognizes that some of the  
19 inspections that they called for are not technically  
20 feasible at this time, and, you know, they have some  
21 allowances in there. Larry could probably speak  
22 further to this, but that was -- all three of the  
23 items we put into that category were BWR VIP items,  
24 where the technology is not there to allow you to do  
25 the particular inspection.

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1 MR. LUKENS: This is Larry Lukens.

2 Probably the classical example of this is  
3 the so-called P9 weld and the core spray shroud the  
4 collar, the P9 weld is inaccessible, it's not visible,  
5 can't get there. Several years ago, we got a technique  
6 approved by EPRI to interrogate this weld by UT, and  
7 that technique was subsequently disqualified because  
8 nobody currently believes we can come up with a UT  
9 technique to interrogate that weld.

10 So, that weld is inaccessible, and that  
11 weld is redundant to other welds, which we can  
12 examine, and which we have examined, we do examine  
13 those at the frequency specified by the BWR VIP, so  
14 that our inability to examine that weld doesn't affect  
15 structural integrity of the connection, it is an  
16 artifact of the way the plant was built, as all BWRs  
17 we build.

18 MEMBER BARTON: I think the concern I've  
19 got about this whole issue is that there were -- you  
20 explained your reasoning for not complying with all  
21 the GALL issues, but yet the audit team did find, when  
22 you did divert to your own program for whatever reason  
23 it was, that you did have to make additional  
24 commitments to that program that you were using, even  
25 though it wasn't a GALL program. So, that kind of

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1 says, hey, how smart was the NRC team that was there  
2 that did the audit that picked these up that made you  
3 do -- that you then did agree to do some additional  
4 commitments to what you were doing. And, there were  
5 several of those in this whole stack of exceptions,  
6 and I guess that was the thing that was most  
7 concerning to me. Suppose somebody didn't pick this  
8 up, and you guys agreed to do additional things to the  
9 program you were doing. And, I don't specifically  
10 remember which ones they were, but there were a few of  
11 those like that.

12 MR. LUKENS: This is Larry Lukens.

13 I remember a few of those.

14 MEMBER BARTON: Yes.

15 MR. LUKENS: They dealt, in my area they  
16 dealt with things like frequency of inspections in  
17 fire protection systems.

18 MEMBER BARTON: Yes, that's one.

19 MR. LUKENS: And, the intervals that we  
20 have used are currently in our TRM, they were derived  
21 from are the same intervals that used to be in tech  
22 specs. They were the intervals that we've used  
23 successfully for as long as we've had a fire  
24 protection program.

25 And, we -- our preference would have been

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## VERIFICATION OF VYNPS LICENSE RENEWAL PROJECT REPORT

Title of Report: Aging Management Program Evaluation Results

Report Number: LRPD-02

Revision:

This report documents evaluations related to the VYNPS license renewal project. Signatures certify that the report was prepared, checked and reviewed by the License Renewal Project Team in accordance with the VYNPS license renewal project guidelines and that it was approved by the ENI License Renewal Project Manager and the VYNPS Manager, Engineering Projects.

License Renewal Project Team signatures also certify that a review for determining potential impact to other license renewal documents, based on previous revisions, was conducted for this revision.

Other document(s) impacted by this revision: ☐ Yes, See Attachment ☒ No**License Renewal Project Team**

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**VYNPS Approval**

Reviewed by	Date: _____
Approved by _____	Date: _____
VYNPS Manager, Engineering Projects	

Flow-Accelerated Corrosion Program

4.13 Flow-Accelerated Corrosion Program

A. Program Description

The Flow-Accelerated Corrosion (FAC) Program at VYNPS is comparable to the program described in NUREG-1801, Section XI.M17, Flow-Accelerated Corrosion.

This program applies to safety-related and nonsafety-related carbon steel components carrying two-phase or single-phase high-energy fluid  $\geq 2\%$  of plant operating time.

The program, based on EPRI Report NSAC-202L-R2 recommendations for an effective flow-accelerated corrosion program, predicts, detects, and monitors FAC in plant piping and other pressure retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions, or repair or replace components as necessary.

This program is credited in the following.

- AMRM-05, High Pressure Coolant Injection System
- AMRM-06, Reactor Core Isolation Cooling and Condensate Storage and Transfer Systems
- AMRM-26, Main Condenser and MSIV Leakage Pathway System
- AMRM-30, Nonsafety-Related Systems and Components Affecting Safety-Related Systems
- AMRM-33, Reactor Coolant System Pressure Boundary

B. Evaluation

1. Scope of Program

a. NUREG-1801: Scope

"The FAC program, described by the EPRI guidelines in NSAC-202L-R2, includes procedures or administrative controls to assure that the structural integrity of all carbon steel lines containing high-energy fluids (two phase as well as single phase) is maintained. Valve bodies retaining pressure in these high-energy systems are also covered by the program. The FAC program was originally outlined in NUREG-1344 and was further described through the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-08. A program implemented in accordance with the EPRI guidelines predicts, detects, and monitors FAC in plant piping and other components, such as valve bodies, elbows and expanders. Such a program includes the following recommendations: (a) conducting an analysis to determine critical locations, (b) performing limited baseline inspections to determine the extent of thinning at these locations, and (c) performing follow-up inspections to confirm the predictions, or repairing or replacing components as necessary. NSAC-202L-

### Flow-Accelerated Corrosion Program

R2 (April 1999) provides general guidelines for the FAC program. To ensure that all the aging effects caused by FAC are properly managed, the program includes the use of a predictive code, such as CHECWORKS, that uses the implementation guidance of NSAC-202L-R2 to satisfy the criteria specified in 10 CFR Part 50, Appendix B, criteria for development of procedures and control of special processes."

b. Comparison to VYNPS Scope

This program applies to safety-related and nonsafety-related carbon steel components carrying two-phase or single-phase high-energy fluid  $\geq$  2% of plant operating time.

(Ref. Appendix C, PP 7028)

The program, based on the recommendations of EPRI Report, NSAG-202L-R2, predicts, detects, and monitors FAC in plant piping and other pressure retaining components. The program includes an evaluation to determine critical locations, baseline inspections to determine the extent of thinning at these locations, and follow-up inspections.

(Ref. Section 1.3, PP 7028 and FAC Susceptible Piping Identification)

CHECWORKS, a predictive code that uses the implementation guidance of NSAC-202L-R2 to satisfy the criteria specified in 10 GFR Part 50, Appendix B, is used in this program.

(Ref. Section 4.3, PP 7028)

VYNPS scope is consistent with NUREG-1801.

## 2. Preventive Actions

a. NUREG-1801, Preventive Actions

"The FAC program is an analysis, inspection, and verification program; thus, there is no preventive action. However, it is noted that monitoring of water chemistry to control pH and dissolved oxygen content, and selection of appropriate piping material, geometry, and hydrodynamic conditions, are effective in reducing FAG."

b. Comparison to VYNPS Preventive Actions

As stated in NUREG-1801, the FAG program is an analysis, inspection, and verification program; thus, there is no preventive action.

VYNPS preventive actions are consistent with NUREG-1801.

Flow-Accelerated Corrosion Program

3. Parameters Monitored/Inspected

a. NUREG-1801! Parameters Monitored/Inspected

"The aging management program (AMP) monitors the effects of FAC on the intended function of piping and components by measuring wall thickness."

b. Comparison to VYNPS Parameters Monitored/Inspected

The VYNPS program monitors wall thickness to ensure that FAC does not lead to loss of intended function of piping and components.  
(Ref. Section 1.1, PP 7028)

VYNPS parameters monitored and inspected are consistent with NUREG-1801.

4. Detection of Aging Effects

a. NUREG-1801! Detection of Aging Effects

"Degradation of piping and components occurs by wall thinning. The inspection program delineated in NSAC-202L consists of identification of susceptible locations as indicated by operating conditions or special considerations. Ultrasonic and radiographic testing is used to detect wall thinning. The extent and schedule of the inspections assure detection of wall thinning before the loss of intended function."

b. Comparison to VYNPS Detection of Aging Effects

Non-destructive examinations (e.g. ultrasonic testing) are used to detect wall thinning at susceptible locations. The extent and schedule of inspections provide reasonable assurance of detection of wall thinning before loss of intended function.

(Ref. Sections 1.2, 1.3 and 4.4.5, PP 7028)

This program is credited with managing the following aging effects.

- loss of material from internal surfaces of selected carbon steel components (AMRM-05, 06, 26, 30, 33)

VYNPS detection of aging effects is consistent with NUREG-1801.

5. Monitoring and Trending

a. NUREG-1801! Monitoring and Trending

"CHECWORKS or a similar predictive code is used to predict component degradation in the systems conducive to FAC, as indicated by specific plant data, including material, hydrodynamic, and operating conditions.

Flow-Accelerated Corrosion Program

CHECWORKS is acceptable because it provides a bounding analysis for FAC. CHECWORKS was developed and benchmarked by using data obtained from many plants. The inspection schedule developed by the licensee on the basis of the results of such a predictive code provides reasonable assurance that structural integrity will be maintained between inspections. Inspection results are evaluated to determine if additional inspections are needed to assure that the extent of wall thinning is adequately determined, assure that intended function will not be lost, and identify corrective actions."

b. Comparison to VYNPS Monitoring and Trending

The EPRI software program, "CHECWORKS," is used to predict component degradation in FAC susceptible piping. The inspection schedule provides reasonable assurance that structural integrity will be maintained between inspections. If degradation is detected such that the predicted wall thickness at the next refueling outage is less than minimum allowable thickness, (or much less than the nominal thickness), additional evaluations or examinations are performed to assure the component's intended function will not be lost and identify corrective actions.

(Ref. Sections 1.2, 4.3 and Appendix E, PP 7028 and Section 3, DP 0072)

VYNPS monitoring and trending are consistent with NUREG-1801.

6. Acceptance Criteria

a. NUREG-1801, Acceptance Criteria

"Inspection results are used as input to a predictive computer code, such as CHECWORKS, to calculate the number of refueling or operating cycles remaining before the component reaches the minimum allowable wall thickness. If calculations indicate that an area will reach the minimum allowed wall thickness before the next scheduled outage, the component is to be repaired, replaced, or reevaluated."

b. Comparison to VYNPS Acceptance Criteria

Based on inspection results, CHECWORKS calculates the number of refueling or operating cycles remaining before the component reaches minimum allowable wall thickness. If calculations indicate that an area will reach minimum allowed thickness before the next scheduled outage, the component is repaired, replaced, or reevaluated.

(Ref. Section 4.4, PP 7028 and Section 3, DP 0072)

VYNPS acceptance criteria are consistent with NUREG-1801.

Flow-Accelerated Corrosion Program

7. Corrective Actions

a. NUREG-1801, Corrective Actions

"Prior to service, components for which the acceptance criteria are not satisfied are reevaluated, repaired, or replaced. Long term corrective actions could include adjusting operating parameters or selecting materials resistant to FAC. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions."

b. Comparison to VYNPS Corrective Actions

If acceptance criteria are not satisfied for particular components, they are repaired, replaced or reevaluated prior to returning to service. Use of improved materials for replaced components and appropriate design changes are part of the VYNPS long-term strategy to mitigate FAC.  
(Ret Sections 1.3 and 4.4, PP 7028 and Section 3, DP 0072)

VYNPS corrective actions are consistent with those discussed in NUREG-1801.

8. Confirmation Process

This attribute is discussed in Section 2.0, Background.

9. Administrative Controls

This attribute is discussed in Section 2.0, Background.

10. Operating Experience

a. NUREG-1801, Operating Experience

"Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems (NRC IE Bulletin No. 87-01; NRC Information Notices [INs] 81-28, 92-35, 95-11) and in two-phase piping in extraction steam lines (NRC INs 89-53, 97-84) and moisture separation reheater and feedwater heater drains (NRC INs 89-53, 91-18, 93-21, 97-84). Operating experience shows that the present program, when properly implemented, is effective in managing FAC in high-energy carbon steel piping and components."

b. Comparison to VYNPS Operating Experience

Operating experience shows that this program has been effective in managing aging effects. Therefore, continued implementation of the program provides reasonable assurance that effects of aging will be managed so that components crediting this program can perform their intended function



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consistent with the current licensing basis during the period of extended operation. For more information on applicable operating experience, see VYNPS Report LRPD-05, Operating Experience Review Results.

**C. References**

DP 0072, Rev. 00, LPC 01, Structural Evaluation of Thinned Wall Piping Components

FAC Susceptible Piping Identification, Rev. 0, May 15, 2000

PP 7028, Rev. 00, LPC 01, Piping Flow Accelerated Corrosion Inspection Program

**D. Summary**

The Flow-Accelerated Corrosion Program has been effective at managing aging effects. The program has been improved through implementation of lessons learned from operating experience. The Flow-Accelerated Corrosion Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

The Flow-Accelerated Corrosion Program at VYNPS is consistent with the program described in NUREG-1801, Section XI.M17, Flow-Accelerated Corrosion.

*Entergy***CONDITION REPORT****CR-VTY-2005-02239**

Originator: Fitzpatrick, James C

Originator Phone: 3086

Originator Group: Eng DE Mech Civil Struct Staff

Operability Required: N

Supervisor Name: Goodwin, Scott D

Reportability Required: N

Discovered Date: 07/28/2005 10:26

Initiated Date: 07/28/2005 10:43

**Condition Description:**

CHECWORKS predictive models for Piping FAC Inspection Program not updated as required per Appendix D of PP 7028.

The CHECWORKS predictive models for the Piping FAC Inspection Program were not updated after the 2002 and 2004 refueling outages as required per Appendix D of PP 7028. Section 4.4.13 of PP 7028 states the FAC Program Coordinator will, as applicable, incorporate the inspection results into the CHECWORKS models for use in planning the scope of the next refueling outage. However, Appendix D Section D.5 of PP 7028 states that the CHECWORKS models shall be updated after each refueling outage to incorporate inspection data taken during the outage for use in planning inspections for the following outages.

There are no operability concerns. The CHECWORKS model results along with previous inspection data and industry operating experience are inputs to determining the scope of inspections for each refueling outage. Scoping for FAC inspections for RFO 24 and RFO 25 was based on CHECWORKS predicted wear rates from the 2000 and 2001 CHECWORKS model updates. Actual measured wear rates from 2001, 2002 and 2004 RFO inspections are an order of magnitude less than the CHECWORKS predicted wear rates. If the 2002 and 2004 inspection data were incorporated into the models the CHECWORKS predicted wear rates would be reduced.

Use of the non-updated CHECWORKS model results as a basis for inspection planning is conservative in that scoping decisions documented in the Inspection Location Worksheets were based on the CHECWORKS predicted wear rates significantly greater than actual measured wear rates.

**Immediate Action Description:**

Update of the CHECWORKS models is in progress.

There is no impact on planned RFO 25 inspection scope. Use of the non-updated CHECWORKS model results as a basis for inspection planning for RFO 25 is conservative in that scoping decisions documented in the Inspection Location Worksheets were based on the CHECWORKS predicted wear rates significantly greater than actual measured wear rates.

**Suggested Action Description:****REFERENCE ITEMS:**

<u>Type Code</u>	<u>Description</u>
PROCEDURE	PP 7028

**Initiated Date:** 7/28/2005 10:43**Owner Group :**Eng DE Mech Civil Struct Mgmt**Current Contact:****Current Significance:** C - CORRECT ONLY**Closed by:****Summary Description:**

CHECWORKS predictive models for Piping FAC Inspection Program not updated as required per Appendix D of PP 7028.

The CHECWORKS predictive models for the Piping FAC Inspection Program were not updated after the 2002 and 2004 refueling outages as required per Appendix D of PP 7028. Section 4.4.13 of PP 7028 states the FAC Program Coordinator will as applicable, incorporate the inspection results into the CHECWORKS models for use in planning the scope of the next refueling outage. However, Appendix D Section D.5 of PP 7028 states that the CHECWORKS models shall be updated after each refueling outage to incorporate inspection data taken during the outage for use in planning inspections for the following outages.

There are no operability concerns. The CHECWORKS model results along with previous inspection data and industry operating experience are inputs to determining the scope of inspections for each refueling outage. Scoping for FAC inspections for RFO 24 and RFO 25 was based on CHECWORKS predicted wear rates from the 2000 and 2001 CHECWORKS model updates. Actual measured wear rates from 2001, 2002 and 2004 RFO inspections are an order of magnitude less than the CHECWORKS predicted wear rates. If the 2002 and 2004 inspection data were incorporated into the models the CHECWORKS predicted wear rates would be reduced.

Use of the non-updated CHECWORKS model results as a basis for inspection planning is conservative in that scoping decisions documented in the Inspection Location Worksheets were based on the CHECWORKS predicted wear rates significantly greater than actual measured wear rates.

**Remarks Description:****Closure Description:**

Version: 1

Significance Code: C - CORRECT ONLY

Classification Code: C

Owner Group: Eng DE Meeh Civil Struct Mgmt

Performed By: Rogers, James G

07/28/2005 13:26

**Assignment Description:**

WX - Procedure Non-Compliance

ESDE

KW-HU Precursor; HU Clock Reset Dept



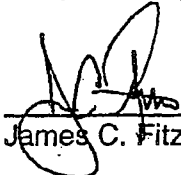
## FOCUSED SELF-ASSESSMENT REPORT

DEPARTMENT: ENVY Design Engineering

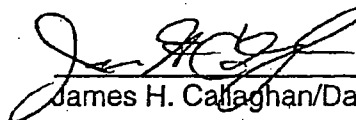
TITLE: Vermont Yankee Piping Flow Accelerated  
Corrosion Inspection Program

Condition Report LO-VTYLO-2003-00327

Prepared By:

 10/27/04  
James C. Fitzpatrick/Date

Approved By:

 10/28/07  
James H. Callaghan/Date

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## ENVY Design Engineering Self Assessment: LO-VTYLO-2003-00327

### EXECUTIVE SUMMMARY

The objective this Self Assessment of the Vermont Yankee Piping Flow Accelerated Corrosion (FAC) Inspection Program was to review the program for compliance with applicable industry standards and NRC guidelines and requirements. A purpose of this assessment was to determine whether or not, problems, or generic weaknesses exist relative to the station implementation of its long term FAC monitoring program.

Specific objectives, evaluation criteria, and the corresponding assessment methodology were developed by the FAC working group (the 5 plant FAC Program Coordinators) using industry documents and previous ENS self-assessment reports. All aspects of the program plan including documentation, management controls, CHECWORKS predictive models, structural evaluations, drawings, condition reports, organizational interfaces were reviewed by the Self-Assessment team. In general, the following conclusions were drawn:

The Vermont Yankee Piping FAC Inspection Program is consistent with other FAC programs among the Entergy Nuclear South plants and throughout the industry. Any guidance provided by the NRC has been and is being followed appropriately.

Several strengths were identified in the methods and documentation of the selection of components for inspection, piping replacements with FAC resistant materials, and the level of FAC related experience of the program engineers.

No weaknesses or deficiencies were identified that would indicate that the VY Piping FAC Inspection Program could impact long-term monitoring of FAC or result in a challenge to nuclear or personnel safety, equipment reliability, or station performance.

Several Areas for Improvement were identified in the areas of formalized documentation of program reports and program related communications, transition issues related to converting to ENN procedures, and in timely updates of the CHECWORKS models.

Recommendations to enhance these areas and other minor process and procedural issues with the program are documented and appropriate actions have been entered into PCRS.

## 1.0 SCOPE OF ASSESSMENT

This assessment will focus on the Vermont Yankee Piping Flow Accelerated Corrosion (FAC) Inspection Program activities and processes to comply with generic letter 89-08. This assessment will include a thorough review and evaluation of the FAC Program processes in accordance with applicable industry standards and NRC guidelines. This assessment will verify that the FAC Program includes systematic methods for predicting which systems are susceptible to FAC, inspecting components determined to be susceptible, analyzing and trending inspection data to determine EC/FAC wear rates, determining future inspection times based on past inspection results, and repairing or replacing piping components determined or predicted to wear below minimum requirements.

This assessment will determine whether or not management controls, problems, or generic weaknesses exist relative to the station implementation of its long term FAC monitoring program.

## 2.0 OBJECTIVES, CRITERIA, & METHODOLOGY

This assessment is the first of five planned FAC program assessments for the ENN plants. Insights and findings from these assessments will be used to develop a common FAC Program for the ENN fleet. Specific objectives, evaluation criteria and the corresponding assessment methodology have been developed by the FAC working group (the 5 plant FAC Program Coordinators). The intent is to evaluate the FAC Program at each plant using essentially the same criteria.

The attributes that follow each of the objectives were taken from previous self assessments performed by ENS, INPO 97-002, "Performance Objectives and Criteria for Operating Nuclear Generating Stations" (OR, EN & OE), NSAC-202L "Recommendations for an Effective Flow-Accelerated Corrosion Program", the NRC Inspection Manual 49001 Sections 02 and 03, and Generic Letter, GL 89-08.

The following objectives and criteria were used to assess the specific areas of the self-assessment to determine the overall health and effectiveness of the Vermont Yankee Piping Flow Accelerated Corrosion (FAC) Inspection Program.

### 2.1 Programmatic leadership/Responsibility

**Objective:** Ensure that Vermont Yankee Nuclear Power Plant (VYNPP) Flow Accelerated Corrosion (FAC) Program is provided with adequate leadership and that the responsibility for the program is clearly defined. Determine if the FAC Program owner and any dedicated backup personnel are qualified for the position.

**Criterion 2.1.1 - Management** Determine if there is an active Management participation in, and commitment to the FAC program.

**Methodology:** Review of all levels of site procedures relating to FAC program to determine extent of Management's role in the program.



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Criterion 2.1.2 - Documentation Determine if there is a station document that defines the overall program.

Methodology: Review station documents for definition and implementation of the FAG program.

Criterion 2.1.3 - Program Awareness Determine if appropriate site personnel are aware of who owns the FAG Program.

Methodology: Review Station documents or interview appropriate site personnel such as operations, system engineers, chemistry supervision, design engineering, and corporate metallurgist to determine their familiarity with the FAG program owner. Document their interactions with the FAG engineer.

Criterion 2.1.4 - Roles & Responsibilities Determine if the roles and responsibilities of the FAG program are clearly defined and understood.

Methodology: Review station documents for definition of FAG program roles and responsibilities. Interview program owner and support groups to determine if the roles and responsibilities are clear and followed.

Criterion 2.1.5 - Training Determine if personnel responsible for the FAG program have received appropriate training for the position.

Methodology: Request documentation or other evidence such as a training matrix or certificates showing the description and completion of training that has been obtained for the FAG program owner and any backup personnel. Such as Introductory FAG, EPRI GHEGWORKS, NDE training, etc.

Criterion 2.1.6 - Qualification Determine if FAC program owner is qualified for the position.

Methodology: Request documentation or other evidence such as a training matrix showing a description and completion of the position qualification.

Criterion 2.1.7 - Bench Strength Determine the bench strength and qualifications/training of backup personnel.

Methodology: Request documentation or other evidence such as a training matrix showing a description and completion of the position qualification.

Criterion 2.1.8 - Personnel Turnover Determine if personnel turnover is an issue for the FAC program.

Methodology: Interview program owner and supervisor to determine length of time in position for incumbent and predecessors. Review method and thoroughness of turnover.

Criterion 2.1.9 - Resources/Schedule Determine if program task/activities are completed in a timely manner and impact of time, schedule, resources, and accelerated milestones.

Methodology: Interview program owner to determine how much time is spent on FAG program during a fuel cycle, other responsibilities other than the FAG program and roles and responsibilities during outages. Interview program owners

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immediate supervisor for his expectations from program owner and perspective of the programs owner workload.

## 2.2 System Susceptibility

**Objective -** Determine if the FAC Program includes systematic methods for categorizing which systems are susceptible to FAC, predicting and analyzing FAC, and for prioritizing inspections. Determine if the methods are consistent with industry practice.

**Criterion 2.2.1 - Susceptibility Review** Determine if there is a formal susceptibility review performed for each system and component that may be susceptible to FAC.

**Methodology:** Perform a review of program documents to ensure that a formal FAC susceptibility evaluation has been performed. Ensure that scope of the review includes all susceptible plant piping shown on plant drawings and includes piping components on vendor supplied equipment. Ensure that the criteria used in the susceptibility evaluation is consistent with NSAC 202L.

**Criterion 2.2.2 - Ranking Criteria** Determine if the criteria used to rank the susceptible piping components in the various systems are in accordance with NSAC 202L or other accepted industry practices.

**Methodology:** Review FAC Program documents to determine whether the guidance provided in NSAC 202L is consistently applied. If other criteria are used, determine if the basis used is documented and defensible.

**Criterion 2.2.3 - Documentation and Reviews** Determine if the susceptibility analysis is adequately documented, checked, and/or independently reviewed.

**Methodology:** Review Program documentation / susceptibility analysis to verify if the analysis was checked or independently reviewed.

**Criterion 2.2.4 - Updates** Determine if the susceptibility analysis report(s) are updated and at what frequency.

**Methodology:** Perform a document review of the susceptibility analysis report to determine if the report(s) are current. Also determine if the reports are updated at an appropriate frequency.

**Criterion 2.2.5 Scope & System Alignment** Determine whether systems and components being ranked are appropriately aligned with plant operating procedures and the pertinent drawings/ flow diagrams. Determine if piping on vendor supplied equipment is included in the scope of FAC program.

**Methodology:** Review program documents to determine whether systems and components being ranked are appropriately aligned with plant operating procedures and the pertinent drawings/ flow diagrams. Review vendor supplied drawings to verify if piping drawings are included in the document system and in the FAC program.

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Criterion 2.2.6 - Small Bore Susceptibility Determine if there is a susceptibility analysis performed for the small-bore piping and if there is inspection priority assigned to the piping.

Methodology: Perform a document review of the small bore susceptibility analysis, if applicable. Otherwise conduct interviews with FAC Responsible engineer to determine how the FAC program handles small bore piping.

Criterion 2.2.7- Department Interface Determine how other plant departments effectively contribute to the Susceptibility Analysis.

Methodology: Perform a document review of site procedures and protocols to determine if the roles and responsibilities for interfacing departments are clearly defined, and there is evidence of input from other plant departments. Conduct interviews with FAC Responsible engineer to determine how effective are the respective departmental inputs to enhancing the FAC program.

Criterion 2.2.8 - Abnormal Conditions Determine how changes in operating conditions, off-normal or abnormal system lineup, component leakage or operating experience are communicated, documented and evaluated for impact on the FAC program.

Methodology: Perform a document review of site procedures and protocols, system health reports, Condition Reports (Event Reports at VY), site and industry operating experience, E-Mail, or other communications to determine how system condition changes or alignment are documented, communicated then evaluated for impact on the FAC program. Conduct interviews with system engineering, operations, and performance groups to evaluate how are changes to system conditions and system alignment affecting the FAC program is documented and communicated to the FAC engineer.

### 2.3 Documentation

**Objective - Ensure that FAC Documentation is in compliance with industry standards and that it is maintained in accordance with established processes and procedures.**

Criterion 2.3.1 - Controlling Program procedure. The controlling program procedure is up to date and is current with respect to industry codes and standards.

Methodology: Review FAC program documents and references to determine if the controlling procedure is up to date and meets the requirements of applicable industry codes and standards. The controlling program procedure should be consistent with NSAC 202L guidelines.

Criterion 2.3.2 – Supporting Documents. Gridding procedures, engineering standards, and engineering directives, etc., are maintained up to date with current revisions.

Methodology: Review FAC program documents and references to determine if the supporting documents are up to date and meet the requirements of applicable industry codes and standards.

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Criterion 2.3.3 - Document Reviews All appropriate program documents (Procedures, Models, Component Evaluations, etc.) are checked and reviewed per plant procedures and/or industry practices.

Methodology: Review FAC Program Documents (including a sample of historical records) to determine if Program Documents are reviewed and checked in accordance with program procedures or industry practices.

Criterion 2.3.4 - Component Database The component inspection database must be properly maintained.

Methodology: Review FAC component database to assure that it is properly updated and maintained.

Criterion 2.3.5 - Post-Outage Report The Post-Outage report must be completed and issued in a timely manner.

Methodology: Review FAC Documentation to assure that the Post-Outage Reports are completed and issued in a timely manner.

Criterion 2.3.6 - CHECWORKS Pass 2 CHECWORKS Pass 2 analysis and records must be up to date and adequately documented.

Methodology: Review FAC Documentation to assure that the CHECWORKS Pass 2 analysis and records are completed in a timely manner.

Criterion 2.3.7 - FAC Program Drawings FAC Program record drawings must document the component locations, the CHECWORKS numbering system, must be up to date. The documentation should be consistent with NSAC 202L Guidelines.

Methodology: Review a sample of plant FAC drawings to ensure that they indicate the component locations, the CHECWORKS numbering system, and they reflect the current plant configuration.

## 2.4 Model Verification and Review

**Objective -** Ensure that FAC predictive computer model used (such as CHECWORKS) is verified, reviewed and maintained in accordance to the plant's FAC Program procedures.

Criterion 2.4.1 - Model Review/Verification Determine if models are reviewed/verified and properly signed off.

Methodology: Review FAC program documents to determine if formal guidance for review/verification and sign off exists for the models. Review one system model to determine if it has been reviewed by a second person prior to being used.

Criterion 2.4.2 - Model Updates Determine if model is updated with projected operating hours for the next outage, current chemistry conditions, and other changes in operating parameters.

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Methodology: Review model to determine that operating parameters such as current chemistry conditions, operating hours and power level information are up to date.

Criterion 2.4.3 - Modeled systems accuracy. Determine if models reflect the complete piping system being modeled.

Methodology: Review a sample of one system model to ensure that all components in the piping system are included in the model.

Criterion 2.4.4 - Component data accuracy. Determine if component information in a system model is correct.

Methodology: Review a segment of a modeled system to ensure correct inputs were used such as material, geometry code, diameter, and nominal thickness. Also review a model segment in which a component has been replaced. Review replacement information for accuracy and ensure system drawings were updated appropriately.

Criterion 2.4.5 - Component Inspection data. Determine if component inspection data has been imported into model and processed correctly.

Methodology: Review a sample of one system model to ensure component inspection data was imported into model according to application guidelines.

Criterion 2.4.6 - Predictive Analyses. Determine if the predictive computer model analyses are reviewed and used as part of the inspection selection process in accordance with program procedures.

Methodology: Review a sample of Pass1 and Pass 2 model results to ensure results are appropriately used for planning component inspections.

## 2.5 Inspection Planning

Objective - Ensure that FAC examination locations are selected in accordance with the site procedures and industry practices.

Criterion 2.5.1 - Inspection Process Determine if there is a procedure or formal process for selecting components for inspection.

Methodology: Review FAC Program documents to identify procedures and/or formal processes used to select components for inspection. Ensure that procedures provide sufficient guidance for component selection, and the guidance is consistent with NSAC 202L recommendations.

Criterion 2.5.2 - CHECWORKS Pass 1 Determine if only CHECWORKS Pass 1 analysis models are used as a basis in the selection process.

Methodology: Review FAC Program CHECWORKS analyses for use of only CHECWORKS Pass 1 analyses. Determine if the rationale for only using a Pass 1 analyses for the inspection/selection process exists and is documented.

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**Criterion 2.5.3 – CHECWORKS Pass 2** Determine if CHECWORKS Pass 2 analysis models are used in the selection process.

**Methodology:** Review FAC Program CHECWORKS analyses for use of CHECWORKS Pass 2 analyses in the inspection/selection process. Determine if analyses are current and performed in accordance with site procedures and NSAC 202L Guidelines.

**Criterion 2.5.4 - Previous Inspections** Determine if & how previous inspection results are used in the selection process.

**Methodology:** Review FAC Program documents to determine if past inspection data is used in the selection process. Determine if the components recommended for repeat inspections in past inspection reports have in fact been inspected or scheduled for inspection.

**Criterion 2.5.5 - Industry Events** Determine if recent and past industry events are considered in the inspection planning process.

**Methodology:** Review a sample of industry operating experience (OE) to insure that it has been factored into the component selection process.

**Criterion 2.5.6 - Selection Documentation** Determine if the results of the inspection planning process are formally documented and if the selection logic for each location is captured.

**Methodology:** Review a sample of component selection documents to determine if the rationale for component selection (or exclusion/deferral) is documented.

**Criterion 2.5.7 - Control Valve Piping** - Determine if susceptible components and piping downstream of control valves are covered in the program.

**Methodology:** Review a sample of plant flow diagrams for several susceptible systems and locate piping sections downstream of control valves. Determine if these locations are inspected and monitored for FAC.

**Criterion 2.5.8 - Turbine Cross Around Piping** Determine if the turbine cross around piping is inspected on a regular basis and if the frequency is supported by inspection data.

**Methodology:** Review the turbine cross around piping inspection reports and available documentation for inspection history, trending, and future inspection/repair/replacement plans.

**Criterion 2.5.9 - Dissimilar Metal Effects** Determine if piping components adjacent to upgraded materials are included in the inspection program scope to detect localized thinning caused by "entrance effect" at dissimilar metal connections.

**Methodology:** Review a sample of plant documents to determine locations of components replaced with FAC resistant materials. Verify inspections of original components adjacent to those replaced with FAC resistant materials.

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**Criterion 2.5.10 - Selection Review** Determine if the piping component inspection list is reviewed by a person other than the originator and also if there are any program requirements for the review.

**Methodology:** Review component selection documents and/or interview responsible individuals for evidence that reviews of component selection documents are performed by another individual than the originator. Ensure evidence of reviews (documented by signature or other means) exists.

**Criterion 2.5.11 - Selection Input** Determine if input from other groups is included in the inspection planning process ((Le., Valve Group, Systems Engineering, Thermal Performance Monitoring, Operations, etc.)

**Methodology:** Review a sample of component selection documents and/or interview responsible individuals for evidence that input and/or reviews by other plant groups have been considered in the selection process.

**Criterion 2.5.12 - Scope Expansion** Determine if the program contains specific guidelines for scope expansion in the case of high or unexpected wear.

**Methodology:** Review program documents for specific scope expansion guidelines for in the case of high or unexpected wear. Review previous inspection reports for evidence that guidelines were followed.

**Criterion 2.5.13 - Normally Closed Valves** Determine if piping downstream of normally closed - but leaking valves is being considered for inspection.

**Methodology:** Review piping susceptibility analysis, previous inspection reports, Thermal Performance Monitoring Data, and condition reports to determine if a sample of piping downstream of normally closed (but leaking) valves is considered for inspection.

**Criterion 2.5.14 - Small Bore Program** Determine if there is an adequate small bore program for prioritizing and scheduling inspections.

**Methodology:** Review piping susceptibility analysis, previous inspection reports, and small bore related documents to determine the scope and schedule of the small bore piping inspection program. Compare plant documents to recommendations contained in Appendix A of NSAC 202L.

## 2.6 Performing Inspections

**Objective -** Ensure that FAC Examinations are performed in accordance with the site procedures and FAC Program documents and that they are consistent with industry standards.

**Criterion 2.6.1 - Procedures** Determine if there are formal procedures for performing inspections.

**Methodology:** Review FAC Program documents to determine if formal procedures exist that provide sufficient guidance for performing FAC Inspections. Ensure this

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guidance is consistent with NSAC 202L. Ensure the procedures are current, properly reviewed, and reflect current industry techniques and practices.

Criterion 2.6.2 - Inspection Grids Determine if component inspection grids are permanently marked or documented to insure that future inspections can be repeated at the same locations.

Methodology: Review FAC Program documents for gridding instructions and determine that the grids are reproducible to ensure repeatability. Determine if the markers used for grid layout are permanent enough to ensure repeatability.

Criterion 2.6.3 - Gridding of Components Determine if inspection gridding is performed in accordance with industry practice and Program requirements.

Methodology: Review several FAC inspection reports, photographs, and drawings of components from past outages to ensure inspection grids cover the entire component, the grid size used is consistent with NSAC 202L, the area on both sides of each pipe to component weld is inspected, and the grids extend upstream and downstream of the inspected component.

Criterion 2.6.4 - Qualifications/Certifications Determine if NDE Inspectors are properly qualified in accordance with the plant procedures and equipment certifications.

Methodology: Review a sample of inspector certificates of qualification from the last outage. Ensure inspectors qualifications were current and reviewed by QA prior to performing inspections, and inspectors were qualified to the proper UT Level for the inspections performed. Review a sample of equipment certifications from last outage and all equipment used in the inspections had current certifications.

Criterion 2.6.5 - Baseline Measurements Determine if UT measurements are taken on all components that are being replaced with susceptible materials.

Methodology: Review a sample of FAC inspection data of replaced components to ensure baseline data was obtained and documented in the FAC Program.

Criterion 2.6.6 - Suspect Readings Determine if suspect readings are verified for accuracy and areas of significant wear are scanned or the size of the grid reduced to identify the extent and depth of the thinning.

Methodology: Review a sample of FAC inspection data for evidence of checking data for suspect UT readings and verification that these readings were investigated and verified for accuracy.

Criterion 2.6.7- Organization of Data Files Determine if there is a formal system for organizing and maintaining the inspection data files.

Methodology: Interview FAC Responsible engineer and review process used for organizing and maintaining inspection data files. Ensure Inspection data is retained in accordance with plant procedures and are available for future retrieval.



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2.7 Data Evaluation

Objective - Determine if the process for collecting, evaluating, analyzing and trending data is effective and is performed in accordance with established standards.

Criterion 2.7.1- UT Data Evaluation Determine if there is a formal process for evaluating UT data and performing wall thinning evaluations.

Methodology: Perform document reviews of UT procedure, data sheets and the component evaluation procedure to determine if the process is adequate for dispositioning components for continued service or replacement.

Criterion 2.7.2 - Evaluation Process Determine if the criteria and process used to evaluate components is in accordance with plant procedures and industry standards.

Methodology: Review evaluation procedure and a sample of evaluations to determine if the methodology used to perform the evaluations is in accordance with plant procedures and whether the evaluations provide the necessary data to effectively disposition the components for continued service.

Criterion 2.7.3 - Document Review Determine if the acceptance evaluations performed for each component are documented and reviewed.

Methodology: Review Program Documentation and a sample of component evaluations to verify if the evaluations are formally documented and are checked or independently reviewed.

Criterion 2.7.4 - Safety Margins Determine if appropriate safety margins are applied in remaining service life evaluations.

Methodology: Perform a document review of the evaluation process and sample some component evaluations to assess what safety margins are applied and whether they are consistent with applicable codes and industry standards.

2.8 Performing Repairs

Objective - Ensure that FAC Repairs/Replacements are performed in accordance with established processes, procedures and applicable codes.

Criterion 2.8.1 - Repairs/Replacement Determine if formal procedures are followed when performing repairs or replacements.

Methodology: Review FAC program documents to determine if formal approved procedures are available that provide guidance for performing repairs and replacements that are consistent with applicable piping codes and meet the intent of NSAC-202L-R2.

Criterion 2.8.2 - External Repairs Determine if external repairs are performed in accordance with applicable codes and standards. There are several ASME code cases that may be utilized for safety related piping and components. Prior NRC

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approval may be required to use these code cases. These code cases can generally be used for non-safety related piping also.

Methodology: Review FAC Program documents and historical records to determine if External Repairs are performed in accordance with approved codes and standards and are consistent with NSAC 202L guidelines. Welding must be accomplished using approved procedures and qualified welders.

Criterion 2.8.3 - Internal Weld Repair Determine if internal weld repairs are performed in accordance with applicable codes and standards.

Methodology: Review FAC Program documents and historical records to determine if internal weld repairs are performed in accordance with approved codes and standards and are consistent with NSAC 202L guidelines. Welding must be accomplished using approved procedures and qualified welders.

Criterion 2.8.4 - Material Upgrade Process Determine if piping material upgrades are accomplished using approved site procedures.

Methodology: Review FAC documentation of material upgrades to ensure that the material upgrades have been reviewed and approved prior to installation in the plant and accomplished using approved procedures and processes.

Criterion 2.8.5 - Material Upgrade Documentation Determine if documentation of material upgrades is included in the FAC program documentation.

Methodology: Review FAC program documents to verify that material upgrade details have been properly incorporated into the plant drawings, specifications, predictive models, and associated data bases.

## 2.9 Long Term Strategy

Objective - Determine if the FAC Program has a long-term strategy that is consistent with the guidance provided in EPRI guideline NSAC-202L-R2, "Recommendations for an Effective FAC Program".

Criterion 2.9.1 - Establishment of a Long Term Strategy Determine if a long-term strategy is in place and if it is effective.

Methodology: Review FAC program documents to determine if a long-term strategy exists and if the strategy is consistent with NSAC-202L guidelines.

Criterion 2.9.2 - Reduction of wear rates Determine if the long-term strategy in place focuses on reducing FAC wear rates.

Methodology: Review FAC long-term strategy to determine if the strategy focuses on reducing wear rates and that the strategy on reducing wear rates is consistent to NSAC-202L guidelines.

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Criterion 2.9.3 - Modeling Long-term Options Determine if analytical models used have been updated to reflect current information and used to evaluate long-term options.

Methodology: Review FAC program documents and a sample of predictive models to determine that all relevant information is up to date, and if model information is used in long-term planning efforts.

Criterion 2.9.4 - Water Chemistry Determine if past and future plant chemistry or water treatment is effectively used to control FAC degradation.

Methodology: Review program documentation to ensure changes in plant chemistry or water treatments are known and this information is used (either through FAC predictive model or other means) in controlling FAC degradation. Also review interface with Chemistry and FAC engineer.

Criterion 2.9.5 - System Changes Determine if system changes are reviewed and evaluated by the appropriate individual or department.

Methodology: Review FAC program documentation to ensure there is a process in place for informing FAC engineer of system changes that may effect FAC susceptible systems and that the effects of these changes to FAC are considered by appropriate department prior to making modifications to FAC susceptible systems. Also, ensure that replacements performed under the FAC program are communicated to system engineering (as well as other related departments) and appropriate drawings are updated with new material changes.

Criterion 2.9.6 - Inspection and Replacement Goals Determine if inspection and replacement goals are developed and documented for the next 3 to 5 years.

Methodology: Review FAC program documentation to determine if inspection and replacement goals for the next 3 to 5 years have been set.

Criterion 2.9.7 - Plant Benefits Determine if there is evidence of continual improvement to the plant due to FAC program efforts.

Methodology: Review FAC program and plant documentation to determine if there has been improvement in areas of water treatment, a reduction of wear in once high FAC susceptible systems, and replacement of susceptible components with corrosion resistant materials.

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### 3.0 EVALUATION SUMMARY

Criterion 2.1.1 - Management: Determine if there is an active Management participation in, and commitment to the FAC program.

Vermont Yankee's response to GL-89-08 was reviewed for commitment to maintaining a FAC Program. The FAC program procedure PP 7028, Section 3, and the Engineering Program Procedure PP 7031 which delineates management responsibilities to the Director level were also reviewed. It was concluded that there is an active Management role in the FAC Program.

Criterion 2.1.2 - Documentation: Determine if there is a station document that defines the overall program.

Program procedure PP 7028, VY Piping FAC Inspection Program defines the responsibilities and implementation requirements for the FAC Program. Engineering Program Procedure PP 7031 delineates management responsibilities to the Director level. These documents along with related station procedures define the overall program.

Criterion 2.1.3 - Program Awareness: Determine if appropriate site personnel are aware of who owns the FAC Program.

Program Procedures PP 7028 and PP 7031 were reviewed and a clear delineation of roles and responsibilities for the various departments for interaction with the FAC Program was found. The FAC Program Coordinator is in design engineering. Also reviewed examples of documentation which demonstrated close ties with other groups for timely notification of leaks, access to system engineering thermal performance reports, and the monthly and weekly chemistry reports. This information is also available on plant web site.

Criterion 2.1.4 - Roles & Responsibilities: Determine if the roles and responsibilities of the FAC program are clearly defined and understood.

Program procedure PP 7028 and PP 7031 clearly define the roles and responsibilities of the various groups that implement and support the FAC Program. Interviews with the Program Engineer clearly illustrated that everyone works together and provides support when needed, and are familiar with the needs of the FAC Program.

Criterion 2.1.5 - Training: Determine if personnel responsible for the FAC program have received appropriate training for the position.

Vermont Yankee and Yankee Atomic training records for the program owner and back-up were reviewed. Both individuals have received the appropriate training for the FAC Program. Examples include the CHECWORKS Training Session from EPRI, an ASME sponsored Assessment of Material Aging and Assessment of Remaining Life evaluation course, and a Piping Flow Accelerated Corrosion (Mechanical Only) course.

Criterion 2.1.6 - Qualification: Determine if FAC program owner is qualified for the position.

There is no qualification matrix for the FAC Program in the ESP Program at this time. However there is a qualification matrix for the MS/DE department that shows the Program Owner is qualified to administer the FAC Program.

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Criterion 2.1.7 - Bench Strength: Determine the bench strength and qualifications / training of backup personnel.

Vermont Yankee and Yankee Atomic training records show that the program owner and back-up have received the appropriate training for the FAC Program. There is no qualification matrix for the FAC Program in the ESP Program at this time. However, there is a qualification matrix for the MS/DE department that shows the program owner and backup are qualified to implement the FAC program. Also, a third design engineer with previous FAC Program experience at other plants is available.

Criterion 2.1.8 - Personnel Turnover: Determine if personnel turnover is an issue for the FAC program.

There is no issue at this time as the program owner has been in this position since the start of the FAC Program. The backup engineer has also been involved with the program since 1993. The current status of the program and future work is well documented which would be a valuable tool if turnover would be necessary.

Criterion 2.1.9 - Resources/Schedule: Determine if program task/activities are completed in a timely manner and impact of time, schedule, resources, and accelerated milestones.

An interview with program owner revealed that the time actually spent on FAC Program is ½ FTE averaged over the fuel cycle. Other responsibilities included ISI and IWE support. The program owner also supports IWE during outages. The actual time spent on FAC is very close to the time budgeted. Normally this works well and emergent work can be fit in with little or no impact to the program. Work planning is excellent and is formally planned using the Engineering Work Control (EWC) process.

However, during the last operating cycle, this was not true. The program owner needed to spend a good deal of time working on the EPU and pushed out many of the program commitments over three months. This was recognized by the program owner and his supervisor as an unusual event. Program tasks are routinely performed on schedule.

An interview with Program owners' supervisor reiterated the issues stated above. After the EPU is finished, the workload will return to normal. The work scheduling process via the EWC is well suited to identify and track items to completion by Program owner and his supervisor.

Criterion 2.2.1 - Susceptibility Review: Determine if there is a formal susceptibility review performed for each system and component that may be susceptible to FAC.

A susceptibility review was performed for the plant piping in accordance with NSAC 202L. This review lumped all the piping systems together, while this approach gives a single place to verify inclusion or exclusion into the program the approach should have been to further separate the small bore review and rank the piping for inspections in terms of inspection priority and risk consequences to the plant. Since the CHECWORKS program for large bore piping provides such ranking. See Area for Improvement (AFI) 2.2-1.

Further review of the report determined that the document is not formal even though there was a review performed. This document is not in the document system nor, is it an attachment to or an appendix to a procedure. Recognizing that a lot of the piping in the plant is corrosion resistant material it does not preclude the remainder of the piping from being prioritized in terms inspection priority and risk consequence. See AFI 2.2-2.

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A review of incorporation of the vendor supplied piping into the susceptible review was also performed by sampling the HPCI system and reviewing, drawing GE191169, with the result that all piping was included.

Criterion 2.2.2 - Ranking Criteria: Determine if the criteria used to rank the susceptible piping components in the various systems are in accordance with NSAC 202L or other accepted industry practices.

A review of the FAC Susceptible Piping Identification Report shows that the guidance provided by NSAC 202L was used to screen the various piping systems for inclusion or exclusion in the FAC program. The report did not rank the piping in terms of inspection priority or risk consequence to the plant. Since ranking for the large bore piping is provided by the CHECWORKS model, it is therefore important that small bore piping system be ranked (AFI 2.2-1). Per interview with the program coordinator this task was scheduled but currently not done due to other work assignment priority.

Criterion 2.2.3 - Documentation and Reviews: Determine if the susceptibility analysis is adequately documented, checked, and/or independently reviewed.

The FAC Susceptible Piping Identification Report was checked to determine if there was an adequate review performed and determined that only a peer review was performed. This report was a program generated document with no requirement for this review. This document is not in the document system nor is it an attachment to or an appendix to a procedure. AFI 2.2-2

Criterion 2.2.4 - Updates: Determine if the susceptibility analysis report(s) are updated and at what frequency.

A review of program procedure PP 7028, Section 3.2.12 post outage activity requires the update and maintenance of the FAC susceptible piping document to reflect plant changes. During 2001 outage, approximately 6 ft of piping (on MSD piping in steam tunnel) was replaced with chrome-moly piping. AOG steam reducing station drains from steam trap to condenser was also replaced. In addition lines ¾" -HCN-188-H1 and ¾" -HCN-189-D3 which are drains from 3"-MSD-4 from the steam traps at pressure reducing station were replaced. In accordance with PP7028 section 3.2.12, the report should have been revised. The last update of this report was May 15, 2000. See AFI 2.2-3

Criterion 2.2.5 Scope & System Alignment: Determine whether systems and components being ranked are appropriately aligned with plant operating procedures and the pertinent drawings/ flow diagrams. Determine if piping on vendor supplied equipment is included in the scope of FAC program.

Feedwater piping drawings 5920-FSI-24 & 5920-FSI-25 and a sampling of the components of the CHECWORKS model were reviewed to verify if the components within the model match with the piping configuration. A sampling of vendor supplied piping using HPCI piping (Vendor drawing G191169 Sht. 2/2) lines 2-HPCI-8, 2-HPCI-9, & 2-HPCI-12 was also checked to determine if those lines were in the FAC program. System line up was checked against OP-2172 to verify line for normal operation.

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Large bore components being ranked are appropriately aligned with plant operating procedures and the pertinent drawings / flow diagrams and vendor supplied equipment piping is included in the scope of FAC program.

Criterion 2.2.6 - Small Bore Susceptibility: Determine if there is a susceptibility analysis performed for the small-bore piping and if there is inspection priority assigned to the piping.

The susceptibility analysis for small bore piping is complete. However, inspection priorities are not documented. Initially, engineering judgment was used to select small bore inspection locations, such as high pressure lines and steam leak offs. Without a priority ranking, it is difficult to determine if all the high priority lines have been selected. Ranking for the small bore lines was scheduled for the summer, 2003, but had to be pushed back due to emergent work on the power uprate project. Aft 2.2-1

Criterion 2.2.7- Department Interface: Determine how other plant departments effectively contribute to the Susceptibility Analysis.

Conducted an interview with the FAC program engineer to define how the respective departmental inputs are processed and updated. Reviewed system engineering variance reports, thermal performance reports and chemistry reports to determine what vital information was available and continues to exist for the development of the ranking for the small bore piping. Reports from the various departments are adequate to assist in performing the susceptibility analysis.

Criterion 2.2.8 - Abnormal Conditions: Determine how changes in operating conditions, off-normal or abnormal system lineup, component leakage or operating experience are communicated, documented, and evaluated for impact on the FAC program.

A document review of site procedures and protocols, system health reports, Event Reports (Condition Reports), site and industry operating experience, and Emails was performed to determine how system condition changes or alignments are documented, communicated then evaluated for impact on the FAC program. Off normal events are reported through the following reports; Monthly Chemistry Report, System Engineering Variance Report, and the Thermal Performance Report. These tools assist in scoping lines for inspection or incorporating in the susceptible report. However the link with operations needs to be strengthened. See Aft 2.2-4

Criterion 2.3.1 - Controlling Program Procedure: The controlling program procedure is up to date and is current with respect to industry codes and standards.

The program procedure is consistent with NSAC 202L guidelines. However, the program procedure was last changed in 2001 (PP 7028 LPC 1, 12/06/01). The FAC coordinator is aware that the procedure is in need for update, but has had limited time to contribute to the effort. Previous self assessments and audits performed on the FAC program have also recommended the updating of the FAC program procedure. There are two existing commitments (LO-VTVLO-2002-00341 and LO-VTVLO-2002-00568) in place for specific additions/improvements to PP7028. This update should include not only update to the procedure content per the commitments but also update the FAC isometric drawings which are part of the program procedure. See Aft 2.3-1

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Criterion 2.3.2 - Supporting Documents: Gridding procedures, engineering standards, and engineering directives, etc., are maintained up to date with current revisions.

The gridding procedure has resided in NE-8053 until recently, when NE-8053 was made obsolete by ENN-NDE 9.05 rev 0. This new procedure does not include FAC gridding guidelines that were once a part of the VY site procedure. The gridding procedure will need to be moved to a new procedure or incorporated into an existing procedure. The FAC engineer is aware of the change, and will add the necessary gridding guidelines removed from the UT procedure to the FAC program procedure as a supplement. This is not only a problem for VY but also for other ENN FAC programs. Existing commitment No. LO-VTYLO-2003-00528 is in place to relocate the component gridding guidelines.

VY has not adopted the new ENN procedure for wall thinning evaluations, ENN-DC-133 for their FAC program. Adoption of the new ENN procedure for VY is TBD. At this time VY still uses its plant specific procedure for evaluating wall thinning (DP 0072). This structural evaluation procedure (DP 0072) should be checked to ensure that the current references shown are up to date and updated accordingly. Modification of DP 0072 and conversion to ENN-DC-133 for wall thinning evaluations is required. See AFI2.3-2.

Criterion 2.3.3 - Document Reviews: All appropriate program documents (Procedures, Models, Component Evaluations, etc.) are checked and reviewed per plant procedures and/or industry practices.

The FAC program procedure, PP 7028, and department procedure DP 0072, for Structural Evaluation of Thinned Wall Piping Components, and several component evaluations were reviewed. The documents were prepared by the FAC engineer and reviewed by Backup FAC engineer. NDE reports are reviewed and checked by a Level III examiner as well as by the FAC engineer.

Criterion 2.3.4 - Component Database: The component inspection database must be properly maintained.

A component inspection database for small bore component inspections exists, but is not up to date. The last revision was in December of 1999. An update of the small bore database is currently in the EWC schedule. AFI 2.2-1.

For large bore components information and all inspection data to date has been included in the CHECWORKS database. At this time CHECWORKS is considered the main component database for large bore components. A separate a FACTRAK import into an Excel spreadsheet was created in 1996 to summarize which large bore components have been inspected, but has not been updated.

Criterion 2.3.5 - Post-Outage Report: The Post-Outage report must be completed and issued in a timely manner.

Section 4.1.12 of PP 7028 requires that Outage Inspection Reports are to be issued within 90 days of startup. The report itself is very detailed, giving a summary of the inspection activities performed, the goals that were planned and accomplished and inspection results. The report also includes recommendations for future replacements or repairs and future required monitoring. This report is prepared by the FAC engineer and is independently reviewed and signed. Reports from the 1999, 2001, and 2002 refueling outages were reviewed. All were issued with 90 days of plant startup.



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Criterion 2.3.6 - CHECWORKS Pass 2: CHECWORKS Pass 2 analysis and records must be up to date and adequately documented.

A Pass 2 analysis was run for all CHECWORKS lines during 1996. After 1996 only the most susceptible lines were run. In 2003, only the feedwater models were run using 1999 UT data. This information was not used to support 2004 scope selection as stated in the "Inspection Location Worksheets / Methods and Reasons for Component Selection" for the 2004 refueling outage. Updates of the CHECWORKS models are scheduled in the EWC process.

Criterion 2.3.7 - FAC Program Drawings: FAC Program record drawings must document the component locations, the CHECWORKS numbering system, must be up to date. The documentation should be consistent with NSAC 202L Guidelines.

FAC large bore location sketches are located in Appendix A of PP 7028. The sketches represent lines in CHECWORKS and all components in the CHECWORKS models are identified on the sketches using the CHECWORKS numbering system. Information on the component location sketches is consistent with the CHECWORKS model and the component numbering system. The sketches reference P&IDs and pipe drawings used to develop drawings, but the FAC sketches can only be updated as a procedure update since they are part of the FAC program procedure.

The component location sketches are not included in the plant drawing list and are not controlled through configuration management. Specific sketches do not reflect current plant configuration and "marked up" pending a revision to the Program Procedure. The FAC drawings also do not reflect all the changes due to material replacements. AFI 2.3-1

Criterion 2.4.1 - Model Review/Verification: Determine if models are reviewed / verified and properly signed off.

The complete CHECWORKS models and wear rate analyses were updated in 1996. These were prepared in-house and reviewed by FAC coordinator. After 1996, only a limited number of models were run by FAC coordinator prior to outages (mainly feedwater piping) and these model updates were not formally documented and reviewed. Updates to the CHECWORKS models should be formally updated and reviewed. See AFI 2.4-1

Criterion 2.4.2 - Model Updates: Determine if model is updated with projected operating hours for the next outage, current chemistry conditions, and other changes in operating parameters.

CHECWORKS database has been updated with current operating hours (up to cycle 29) and heat balance parameters are current. There have been no significant chemistry changes performed at W, so chemistry parameters remain unchanged. FAC coordinator is aware of future plant plans such as starting HWC and power uprate and will update CHECWORKS according when these plans are implemented. The CHECWORKS models should be updated with UT data from 2001 and 2002 inspections. An update of the CHECWORKS models is currently in the EWC schedule. The CHECWORKS models should be formally updated and reviewed. AFI 2.4-1

Criterion 2.4.3 - Modeled Systems Accuracy: Determine if models reflect the complete piping system being modeled.

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A detailed review of the CHECWORKS model for a section of the feedwater system (Discharge line from pump P1-1-A to 24" FW header, FAC sketch No. 001) was performed. The modeled line segment included all components in the line from pump nozzle to the feedwater header. Component identifiers in CHECWORKS model matched identifiers on FAC drawings. The complete line was modeled in CHECWORKS.

Criterion 2.4.4 - Component Data Accuracy: Determine if component information in a system model is correct.

Review of CHECWORKS line segment FDW-001 showed all component information to be correct and verified by the heat balance and flow diagrams. Portions of the Feedwater Flush lines 8"-FDW-22A & 10"-FDW-23A on Location Sketch 022 have been upgraded to A335-P11 material. The P&ID, the CHECKWORKS model, and the FAC drawing were reviewed. While the P&ID and the CHECKWORKS model were updated, the FAC Component Location Sketches were only "marked-up". AFI2.3-1.

Criterion 2.4.5 - Component Inspection Data: Determine if component inspection data has been imported into model and processed correctly.

Last inspection (2002) data was imported into CHECWORKS by NDE and reviewed to ensure that the data matched data logger readings. The UT data matrix from CHECWORKS is printed out and signed by NDE. Though the data was imported into CHECWORKS, it has not been evaluated in CHECWORKS or used to analyze wear rates for the 2004 refueling outage inspection selection. This is stated in the "Inspection Location Worksheets / Methods and Reasons for Component Selection" for the 2004 refueling outage. Updates of the CHECWORKS models are scheduled in the EWC process. AFI 2.4-1.

Criterion 2.4.6 – Predictive Analyses: Determine if the predictive computer model analyses are reviewed and used as part of the inspection selection process in accordance with program procedures.

A review of PP 7028 rev 1, Appendix A, Component Location Sketch 008, and the associated Pass1/Pass2 results was performed. Outage inspection plans considered these results in the location selection process. For example, Pass 2 analysis from the 2001 CHECWORKS run was used when developing the scope for 2002 outage. This is documented in the FAC inspection scope worksheets for the 2002 refueling outage which describes the reasoning behind the selection of each component scoped for the outage. Though the components selected were inspected during 2002, the inspection data recorded for that component was not used as part of the wear analysis in CHECWORKS for the 2004 scope. This is stated in the "Inspection Location Worksheets / Methods and Reasons for Component Selection" for the 2004 refueling outage. Updates of the CHECWORKS models are scheduled in the EWC process. AFI 2.4-1.

Criterion 2.5.1 - Inspection Process: Determine if there is a procedure or formal process for selecting components for inspection.

Reviewed program procedure PP 7028 where Section 4.4.1 specifies the process for selecting components and Appendix E of PP 7028 defines the criteria for selection of components for inspection. This approach is consistent with NSAC 202L R2 guidelines.

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Criterion 2.5.2 - CHECWORKS Pass 1: Determine if only CHECWORKS Pass 1 analysis models are used as a basis in the selection process.

CHECWORKS Pass 1 analysis output is only used to exclude lines from the inspection selection process in terms of susceptible or not susceptible. Since a large number of the lines in the large bore FAC program were either originally FAC resistant Chrome-moly piping materials or have been replaced with FAC resistant materials and there are only few segments that have no inspection data, this approach is prudent.

Criterion 2.5.3 - CHECWORKS Pass 2: Determine if CHECWORKS Pass 2 analysis models are used in the selection process.

Generally most of the inspection selections from the CHECWORKS output are from the Pass 2 analysis output. This is consistent with the NSAC 202L approach. However, the model was last updated on October 24, 2001. Industry practice is to update the CHECWORKS models after each refueling outage. INPO in an industry operating experience (OE 12343) identified unanticipated wall thinning in feedwater piping as the result of relying on a dated CHECWORKS model. The OE highlighted the changes in component ranking occurred as result of not including the latest inspection data. AFI 2.4-1

Criterion 2.5.4 - Previous Inspections: Determine if & how previous inspection results are used in the selection process.

Criteria for selecting components for inspection during a refueling outage are contained in the "Inspection Location Worksheets/Methods and Reasons for Component Selection". One criterion is for components selected for measured or apparent wear found during previous inspections. Inspection Nos. 01-03 & 01-04, component Nos. FD01EL01 and FD01TE05 as shown on Sketch 004 were tracked from the 2001 inspection report which recommended re-inspection in 2004. A review of the work scope for 2004 included these components for re-inspection. Components recommended for repeat inspections in past inspection reports have been re-inspected.

Criterion 2.5.5 - Industry Events: Determine if recent and past industry events are considered in the inspection planning process.

The "Inspection Location Worksheets/Methods and Reasons for Component Selection" for the 2004 RFO were reviewed. Under the criterion for "Largebore Components Identified by Industry Events/Experience", a total of 18 events since January 2001 are listed. From Surry-1 OE was tracked for a leak in the 8" condenser drain header for the 3<sup>rd</sup>/4<sup>th</sup> point FW Heater vents, the thinning in the Gland Steam piping inside the condenser and the 12" condenser drain header from the MS Drain Trap Lines. Similar piping at VY is an 8" low point drain header, which is scheduled for inspection during the 2004 RFO. The other 17 OE's were reviewed and found either they were dispositioned by scheduling for future inspection or explaining why no further action is required.

Criterion 2.5.6 - Selection Documentation: Determine if the results of the inspection planning process are formally documented and if the selection logic for each location is captured.

Reviewed program procedure PP 7028 which includes the section on "Inspection Location Worksheets / Methods and Reasons for Component Selection". These worksheets provide a rigorous and thorough method to aid in the identification and selection of components for inspection. It includes all the selection criteria necessary for a thorough

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review of small bore, large bore, feedwater heater shells, and cross-around piping. The worksheets address inspections based on previous inspection results, CHECWORKS evaluations, CHECWORKS model calibration, OE, off normal flow conditions, malfunctioning equipment such as leaking valves, and engineering judgment. The worksheets prepared by the program owner and reviewed by the backup FAC program Engineer. Components identified in the worksheets are compiled in the Scoping memo to Program Owners supervisor.

The worksheets used to select inspections should be considered a program strength STR 2.5-1. They present a thorough, rigorous, documented approach to inspection selection incorporating all the criteria in NSAC-202L, and site specific issues.

Criterion 2.5.7 - Control Valve Piping: Determine if susceptible components and piping downstream of control valves are covered in the program.

Plant flow diagrams and inspection reports on piping and components up and down stream of flow control valves FCV6-12A and -128 were reviewed. Up and downstream components of FCV6-12A (FD07RD02, FD07RD03 and FD07SP03) were inspected in 1990, 1993 and 1995. Up and down stream components of FCV6-128 (FD08SP02 and FD08RD03) were inspected in 1995. VY FAC program effectively addresses piping downstream of flow control valves.

Criterion 2.5.8 - Turbine Cross Around Piping: Determine if the turbine cross around piping is inspected on a regular basis and if the frequency is supported by inspection data.

The "Inspection Location Worksheets/Methods and Reasons for Component Selection" for the 2004 RFO was reviewed for the selection of the cross around piping. Also, a sampling of the 1998 and 1995 refueling outage inspection reports was performed. From these it can be concluded that the cross around piping has numerous inspections and the plans for future inspections as documented the 2004 inspection selection demonstrate that the piping is inspected on a frequent basis and is more than adequate.

Criterion 2.5.9 - Dissimilar Metal Effects: Determine if piping components adjacent to upgraded materials are included in the inspection program scope to detect localized thinning caused by "entrance effect" at dissimilar metal connections.

Reviewed plant flow diagrams for instances of non susceptible materials (chrome-moly, stainless steel) adjacent to susceptible materials (carbon steel). Although there are not many instances of dissimilar metal interfaces at VY, one interface was found on feedwater line 4"-FDW-4, sketch 017. The chrome component was pipe FD04SP12 connected to a carbon steel reducer FD04RD01. These components were inspected in 11/99, as documented on inspection data sheet YA-UT-112-222. The VY FAC program effectively addresses dissimilar metal connections.

Criterion 2.5.10 - Selection Review: Determine if the piping component inspection list is reviewed by a person other than the originator and also if there are any program requirements for the review.

The "Inspection Location Worksheets/Methods and Reasons for Component Selection" for the 2004 RFO were reviewed. The worksheets were reviewed and documented by signature. There is no program or procedural requirement for the review. Existing commitment No. LO-VTYLO-2002-341 is in place to formalize the Inspection Location

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Worksheet process. Documentation and review requirements will be included in the procedure update.

Criterion 2.5.11 - Selection Input: Determine if input from other groups is included in the inspection planning process ((Le.! Valve Group, Systems Engineering, Thermal Performance Monitoring, Operations, etc.)

Reviewed the system engineering production variance report and thermal performance report and determined that those reports are good sources for input into the selection process. Interviewed the program owner as to which other group contributed to the selection process and another good source cited is the operating experience group who routinely distribute issue FAC related industry events.

Criterion 2.5.12 - Scope Expansion: Determine if the program contains specific guidelines for scope expansion in the case of high or unexpected wear.

Reviewed program procedure PP 7028, section 4.4.7.2 and Appendix E relating to criteria for scope expansion. Reviewed 1996 Outage inspection report with specific examples of scope expansion as documented in data sheets YA-UT-112-95, YA-UT-112-114 & YA-UT-112-128 due to high or unexpected wear for the feedwater and condensate system.

Criterion 2.5.13 - Normally Closed Valves: Determine if piping downstream of normally closed - but leaking valves is being considered for inspection.

Reviewed the thermal performance variance report (1999) that shows valve leakage by indication of tail pipe temperature measurement with associated inspection during the 1999 refueling outage. Inspection data sheets YA-UT-112-220/221/222 AND YA-UT-112-214/215/216, document the inspections.

Criterion 2.5.14 - Small Bore Program: Determine if there is an adequate small bore program for prioritizing and scheduling inspections.

Reviewed piping susceptibility analysis, previous inspection reports, and small bore related documents to determine the scope and schedule of the small bore piping inspection program. Compare plant documents to recommendations contained in Appendix A of NSAC 202L. Small bore piping inspections are not ranked or prioritized. See AFI 2.2-1

Criterion 2.6.1 - Procedures: Determine if there are formal procedures for performing inspections.

Reviewed program procedure PP 7028 section 4.4.4. "Prepare piping components for inspection", Section 4.4.5, "Perform UT inspections", and Section 4.4.6 for Level III and compliance responsibilities. The procedure specific instructions and guidance for performing FAC inspections are consistent with NSAC 202L Rev.2.

Program procedure PP 7028 references NDE Procedure NE 8053 which has been superseded by ENN-NDE-9.05 Rev.O and subsequently needs to be revised. In addition the details for performing gridding do not exist in the new procedure and no active procedure contains those instructions. Therefore a new procedure has to be generated or the gridding instructions incorporated in the program procedure. Commitment LO-VTYLO-2003-00528 was previously generated to track the development of a FAC gridding procedure.

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Criterion 2.6.2 - Inspection Grids: Determine if component inspection grids are permanently marked or documented to insure that future inspections can be repeated at the same locations.

Reviewed program procedure PP7028 Section 4.4.4.2 which references procedure NE 8053 Appendix A for gridding instructions. This procedure states the requirements for gridding to ensure the applied grids are documented and reproducible. Procedure NE 8053 has been superseded by ENN-NDE-9.05 Rev.O and has no gridding instructions. As a consequence a new procedure needs to be generated. Commitment LO-VTYLO-2003-00528 was previously generated to track the development of a new FAC gridding procedure.

Criterion 2.6.3 - Gridding of Components: Determine if inspection gridding is performed in accordance with industry practice and Program requirements.

Reviewed program procedure PP7028, Section 4.4.4.2 which references procedure NE 8053 Appendix A for gridding instructions. This procedure states the requirement for gridding to ensure reproduction and repeatability. Also reviewed inspection data sheet 8053-02-111 for component FD14EL05 and data sheet 8053-02-110 for component FD14TE02 from the 2002 refueling outage and concluded that the gridding is consistent with the requirements of NSAC 202L Rev.2 and industry standards.

Criterion 2.6.4 - Qualifications/Certifications: Determine if NDE Inspectors are properly qualified in accordance with the plant procedures and equipment certifications.

Reviewed certification / qualification records for two FAC inspectors and determined that the processing and review of the technicians qualification and certification were conducted and accepted in accordance with plant protocol.

Criterion 2.6.5 - Baseline Measurements: Determine if UT measurements are taken on all components that are being replaced with susceptible materials.

No baseline measurements have been performed to date. However no permanent large bore replacements with carbon steel piping have been performed due to FAC related damage.

Criterion 2.6.6 - Suspect Readings: Determine if suspect readings are verified for accuracy and areas of significant wear are scanned or the size of the grid reduced to identify the extent and depth of the thinning.

Reviewed data sheet YA-UT-112-213 for component FD07EL01 for counter-bore and YA-UT-112-238 for component FD14SP03 with suspect reading lower than area reading and data sheet showed readings were re-taken and new measurement replaced the previous one.

Criterion 2.6.7- Organization of Data Files: Determine if there is a formal system for organizing and maintaining the inspection data files.

Reviewed program procedure PP 7028 with particular reference to Sections 4.4.1.3 and 6.3 which require formal record retention. Interviewed FAC program owner for compliance and determined inspection records are retained in accordance with PP 7028.

Criterion 2.7.1- UT Data Evaluation: Determine if there is a formal process for evaluating UT data and performing wall thinning evaluations.

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DP 0072 is used to evaluate components for continued service or replacement and outlines a formal process to perform evaluations. Evaluations are not considered calculations but they are reviewed and signed by an independent reviewer and are permanently stored by records for plant lifetime. Safety class piping and components under ASME section XI requirements are dispositioned in accordance with DP 4027.

UT data is reviewed by Level III examiner and signed. Reviewed 2000 Outage Report Inspection No. 2000-04, DP 0072 provides a formalized process, data sheets, and is found to be adequate for dispositioning components for continued service or replacement.

With the removal of the FAC related guidelines from the UT procedure, it is recommended that the FAC program procedure be updated with these UT data requirements to ensure that the formal process for gathering FAC UT data is maintained. Commitment LO-VTYLO-2003-00528 was previously generated to track the development of a new FAC gridding procedure.

Criterion 2.7.2 - Evaluation Process: Determine if the criteria and process used to evaluate components is in accordance with plant procedures and industry standards.

The FAC program document, PP 7028 rev 1, refers to DP 0072 for evaluating components. Component evaluations are performed in accordance with plant procedure DP 0072, "Structural Evaluation of Thinned wall piping components. At this time, VY is not required to perform evaluations based on ENN-DC-133. Component evaluations are also consistent with industry procedure NSAC-202L.

Reviewed 2000 Outage Report Inspection No. 2000-04, DP 0072 provides a formalized process, data sheets, and is found to be adequate for dispositioning components for continued service or replacement.

Criterion 2.7.3 - Document Review: Determine if the acceptance evaluations performed for each component are documented and reviewed.

A review of the 2000 Outage Report Inspection No. 2000-04, the completed acceptance evaluation includes the component evaluations, NDE reports, and structural evaluations (entire component evaluation worksheet) was performed. These are reviewed, checked, and approved. All worksheets are stored in records for plant lifetime.

Criterion 2.7.4 - Safety Margins: Determine if appropriate safety margins are applied in remaining service life evaluations.

A safety margin of 1.2 on predicted wear rate is used per procedure DP 0072. NSAC-202L-R2 identifies but does not stipulate a value to be used for the safety factor (SF). DP 0072 Rev 1 uses an SF = 1.2. This is consistent with other plants which use either SF = 1.1 or 1.2.

Criterion 2.8.1 - Repairs/Replacement: Determine if formal procedures are followed when performing repairs or replacements.

Formal procedures exist for repair/replacement. Safety class ASME section XI components are dispositioned under DP 4027, and component repairs or replacements are performed under AP 0070. Non-safety repairs/replacements would be controlled via maintenance work orders for like-for-like. For upgraded material replacements, an engineering recommendation, followed by an equivalency evaluation and either a minor

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mod or design change to implement the replacement. AP 0070 "ASME Section XI Repair and Replacement Procedure" provides a formal process, that is consistent with ASME Section XI and NSAC-202L-R2.

Criterion 2.8.2 - External Repairs: Determine if external repairs are performed in accordance with applicable codes and standards. (There are several ASME code cases that may be utilized for safety related piping and components. Prior NRC approval may be required to use these code cases. These code cases can generally be used for non-safety related piping also.

All external weld repairs are considered temporary, are performed using approved procedures, and require approval from the ANII. These are either permanently repaired or replaced during the next opportune time or outage. External repairs to Safety Class Piping would require a relief request and would be performed under the requirements of AP 0070, "ASME Section XI Repair and Replacement Procedure". No external repairs to Safety Class piping due to FAC related damage have been performed at VY.

Criterion 2.8.3 - Internal Weld Repair: Determine if internal weld repairs are performed in accordance with applicable codes and standards.

Internal weld repairs on non Safety Class piping are considered permanent, are performed using approved procedures, and require approval from the ANII. Internal weld repairs to Safety Class Piping are performed under the requirements of AP 0070, "ASME Section XI Repair and Replacement Procedure" using approved welders and welding procedures. This is consistent with ASME Section XI and NSAC-202L-R2 guidelines.

Criterion 2.8.4 - Material Upgrade Process: Determine if piping material upgrades are accomplished using approved site procedures.

Equivalency evaluations, engineering recommendations, and mod packages for material upgrades due to FAC are reviewed and approved prior to installation in the plant. Replacement of FAC susceptible systems with Cr-Mo (P11 or P22) is common knowledge plant-wide and is not stated in FAC program procedure. All material changes are shown on system P&IDs.

PP 7028, does not identify a specific process or procedure to be used when making a material upgrade. After the FAC engineer determines that a material upgrade is required, the Design Engineering Group performs the required evaluations and develops the modification packages using the standard design processes provided by AP 0020, and AP 6008.

Documents pertaining to modifications made to line 1"-MSD-407 (dated 4-3-95) and line 2"-MSD-406 (dated 4-10-95) were reviewed and found reasonable. Additionally, document VY-DC-2003-02, an in-process modification package was likewise reviewed and found to be reasonable.

Criterion 2.8.5 - Material Upgrade Documentation: Determine if documentation of material upgrades is included in the FAC program documentation.

Material changes are captured on the plant P&IDs and not the plant's line specification (the Ebasco Piping Specification QC-10 line list is historical). For the FAC program,



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changes to material have been updated in CHECKWORKS but not all updated lines have been captured in the FAC system susceptibility documentation, and FAC isometrics. See AFI2.2-3.

Portions of the Feedwater Flush lines (8"-FDW-22A & 10"-FDW-23A) have been upgraded to A335 P11 material. The P&ID, the CHECKWORKS model, and the FAC drawing were reviewed. While the P&ID and the CHECKWORKS model were updated, the FAC Component Location Sketches were only "marked-up". See AFI 2.3-1.

Criterion 2.9.1 - Establishment of a Long Term Strategy: Determine if a long-term strategy is in place and if it is effective.

VY is a BWR which has limited chemistry options for reducing FAC. The most effective long term method for reducing FAC wear is replacements with FAC resistant materials. VY has been vigilant on replacing susceptible systems with FAC resistant materials in order to reduce FAC long term. Areas that have been replaced with FAC resistant material to date are:

- o MS Drain Lines to #2 FDW heaters downstream of LCV
- o MS drain bypass lines to condenser downstream of LCV
- o FDW flush lines from normally closed valves to pressure reducing orifices near the condenser.
- o FDW pump bypass lines for normally closed valves to the condenser.
- o Turbine cross around piping (7 of 8 lines).
- o Main steam small bore drains from HPCI and RCIC turbine steam supply to the condenser.
- o Steam Leads continuous drain to the condenser downstream of turbine stop/control valves.
- o Two condensate return lines from the AOG steam pressure reducing station to the condenser.
- o LP turbine casings including the extraction steam stubs
- o Extraction nozzles and partial shell replacement on #2 HP FW heater
- o #3 & #4 feedwater heaters
- o #5 feedwater heaters in the condenser neck

Other systems such as feedwater heater vents are planned for replacement with FAC resistant material due to the planned 20% power uprate. Replacements with FAC resistant materials performed to date are a major part of reducing FAC rates which is an important part of a long term strategy per NSAC-202L R2. Vermont Yankee's proactive piping replacements with FAC resistant material is considered as a program strength. See STR 2.9-1

Criterion 2.9.2 - Reduction of Wear Rates: Determine if the long-term strategy in place focuses on reducing FAC wear rates.

Replacement efforts are the primary focus on reducing wear rates and consistent with NSAC-202L guidelines as stated in Criterion 2.9.1 above.

Criterion 2.9.3 - Modeling Long-Term Options: Determine if analytical models used have been updated to reflect current information and used to evaluate long-term options.

The CHECKWORKS database has been updated with current operating hours (up to cycle 29) and heat balance parameters are current. There have been no significant chemistry changes performed at VY, so chemistry parameters remain unchanged. The FAC

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coordinator is aware of future plant plans such as starting HWC and power uprate and will update CHECWORKS according when these plans are implemented.

Though inspection data for the last two outages have been imported into CHECWORKS, this information must be incorporated into the current models and models ran for results. An update of the CHECWORKS models is currently in the EWC schedule. The updates should be formally updated and reviewed. See AFI 2.4.1.

Criterion 2.9.4 - Water Chemistry: Determine if past and future plant chemistry or water treatment is effectively used to control FAC degradation.

Since VY is a BWR, there is very little that can be done to reduce FAC wear rats through water chemistry changes. Dissolved oxygen in the final feedwater has been maintained in the 20 to 30 PPB range from 1996 to 2003. Future plans to start HWC may affect chemistry with respect to FAC. Monitoring of monthly chemistry reports for feedwater dissolved oxygen and iron transport will be performed.

Criterion 2.9.5 - System Changes: Determine if system changes are reviewed and evaluated by the appropriate individual or department.

Reviewed FAC program documentation to ensure there is a process in place for informing FAC engineer of system changes that may effect FAC susceptible systems and that the effects of these changes to FAC are considered by appropriate department prior to making modifications to FAC susceptible systems and to ensure that replacements performed under the FAC program are communicated to system engineering (as well as other related departments) and appropriate drawings are updated with new material changes.

Since the VY FAC Coordinator is part of the Design Engineering Group, he has direct access to information on system changes such as modifications and replacements being developed that may affect FAC susceptible systems. This is considered a strength of the program. See STR 2.9-2

Criterion 2.9.6 - Inspection and Replacement Goals: Determine if inspection and replacement goals are developed and documented for the next 3 to 5 years.

VY does not have a planned replacement goal for the next three to five years. Replacements have been based on current need. Also many piping systems which would have been found to be highly susceptible to FAC were originally designed with resistant materials or have already been replaced with FAC resistant materials. VY has made a conscious effort to replace piping systems and components that are susceptible with FAC resistant materials. STR 2.9-1

Criterion 2.9.7- Plant Benefits: Determine if there is evidence of continual improvement to the plant due to FAC program efforts.

The ongoing effort of replacing systems with FAC resistant material has drastically reduced the amount of inspections performed during refueling outages. On average the number of inspections performed are around 20 to 30 piping components which is far below the average of typical plants. This is seen as a program strength. STR 2.9-1

#### 4.0 CONCLUSIONS AND RECOMMENDED ACTIONS

Objective 2.1 Programmatic Leadership/Responsibility - Ensure that Vermont Yankee Nuclear Power Plant (VYNPP) Flow Accelerated Corrosion (FAC) Program is provided with adequate leadership and that the responsibility for the program is clearly defined. Determine if the FAC Program owner and any dedicated backup personnel are qualified for the position.

##### Conclusion

There is an active Management role in the FAC Program. Program procedures define the responsibilities, implementation requirements, and interactions between the various plant departments that implement and support the FAC Program. The FAC Program owner and the assigned backup are qualified to administer the FAC Program. Also, a third design engineer with previous FAC Program experience at others plants is available.

Personnel turnover is no issue at this time as the program owner has been in this position since the start of the FAC Program. The backup engineer has also been involved with the program since 1993. The current status of the program and future work is well documented which would be a valuable tool if turnover would be necessary. The experience of both engineers along with a low turnover is considered as a program strength. SiR 2.1-1

Time actually spent on the FAC Program is ½ FTE averaged over the fuel cycle. The actual time spent on FAC is very close to the time budgeted. Normally this works well and emergent work can be fit in with little or no impact to the program. Work planning is excellent and is formally planned using the Engineering Work Control (EWC) process.

However, during the last operating cycle, this was not true. The program owner needed to spend a good deal of time working on the EPU and pushed out many of the program commitments over three months. This was recognized by the program owner and his supervisor as an unusual event. Program tasks are routinely performed on schedule. An interview with Program owners' supervisor reiterated the issues stated above. After the EPU is finished, the workload will return to normal. The work scheduling process via the EWC is well suited to identify and track items to completion by Program owner and his supervisor.

##### Areas for Improvement

None identified for Objective 2.1

##### Strengths

###### STR 2.1-1

The plant and FAC related experience of both the FAC program engineer and the backup engineer, program documentation, and low turnover is considered as a program strength.

Objective 2.2 - System Susceptibility- Determine if the FAC Program includes systematic methods for categorizing which systems are susceptible to FAC, predicting and analyzing FAC, and for prioritizing inspections. Determine if the methods are consistent with industry practice.

##### Conclusion

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A susceptibility review was performed for the plant piping in accordance with NSAC 202L. This review evaluated all plant piping systems (large bore and small bore) for susceptibility to FAC. The scope of the document was to evaluate each system as either susceptible or not and if so, to classify each system for the methodology for evaluation. This approach gives a single place to verify inclusion or exclusion into the program. The report did not rank the piping in terms of inspection priority or risk consequence to the plant. No attempt to rank inspection priorities was made within the scope of this document.

Large bore components which are ranked for inspection priority using CHECWORKS are appropriately aligned with plant operating procedures and the pertinent drawings / flow diagrams. Vendor supplied equipment piping is included in the scope of FAC program.

Inspection priorities for small bore piping are not formally documented. Initially, engineering judgment was used to select small bore inspection locations, such as high pressure lines and steam leak offs. The majority of small bore inspections at VY were performed in 1993 and 1995 prior to the publishing of ranking criteria in Revision 1 of NSAC 202L. Without a formal priority ranking, it is difficult to determine if all the high priority lines have been selected. The recommended approach contained Appendix A of NSAC 202L is to rank the small bore piping for inspections in terms personal safety and consequences of failure. The formal ranking will insure that all the high priority lines are inspected. AFI 2.2-1

The review of the susceptibility report determined that the document is not formal even though there was a peer review was performed. The report was a program generated document with no requirement for this review. This document is not in the records management system as a separately controlled document nor is it an attachment to or an appendix to a procedure. AFI 2.2-2

A review of program procedure PP 7028, Section 3.2.1.2 post outage activity requires the update and maintenance of the FAC susceptible piping document to reflect plant changes. Piping material changes made during the 2001 refueling outage have not been incorporated into the report. AFI 2.2-3

Inputs from other plant departments which impact the susceptibility evaluation and inspection priorities include engineering monthly thermal performance monitoring and chemistry reports. These are adequate to assist the FAC program engineer in performing the susceptibility analysis. Off normal events affecting the FAC program are reported through PCRS, chemistry report, and the System Engineering Production Variance Report. These tools assist in scoping lines for inspection or incorporating in the susceptible report. However, the link with operations needs to be strengthened. AFI2.2-4 A recommendation is to develop a formal method for Operations Department to communicate changes in operating conditions, off-normal or abnormal system lineups to FAC Program for assessment.

### Areas for Improvement

#### AFI2.2-1

Small bore piping inspections are not formally ranked or prioritized. Appendix A of NSAC-202L, Rev.2 provides recommendations for an effective small bore FAC program. Once lines are categorized as susceptible to FAC, it provides criteria for prioritizing inspections based on consequences to the plant. It is recommended that a ranking of small bore

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piping in accordance Appendix A of NSAC-202L Rev.2 be performed and formally documented.

### Consequences

Susceptibility small bore lines have been identified in the piping FAC susceptibility analysis. A large number of small bore inspections at VY were performed in 1993 and 1995 prior to the publishing of ranking criteria in Revision 1 of NSAC 202L. Engineering judgment with respect to personal safety and consequences of failure were used in the location selections. Additional inspections have been performed each refueling outage since 1995. From 1992 to 2002, approximately 110 sections of small bore piping have been inspected, some sections have multiple inspections. This represents a significant portion of the total susceptible small bore population. Given the large number of inspections performed to date, these should include all high priority locations. Also, lines showing significant wear have been replaced with FAC resistant materials. A formal ranking and inspection prioritization will insure that all high priority lines are inspected.

### Recommendation

Update the FAC small bore database to include a detailed ranking of the small bore piping in terms of inspection priority and risk consequence to the plant. This activity is currently on the EWC schedule for the FAC Program activities. No new condition report is required.

### AFI2.2-2

The susceptibility for the plant piping was performed and reviewed in accordance with NSAC 202L. However it is a program generated document not formally included into the plant records management system. This document resides in the FAC Program Notebook and is controlled by the FAC Program Coordinator. The VY document system in place prior to becoming Entergy only assigned formal numbers to calculations. No system was in place to number or catalog "reports" other than through incorporation into the program of job files.

### Consequences

The susceptibility review was performed for the plant piping in accordance with NSAC 202L is an internal program document and is controlled by the FAC Program owner. Since the document is not in the formal records management system the possibility of obsolescence or loss with personnel turnover exists.

### Recommendation

An update to the FAC susceptibility evaluation is currently on the EWC schedule. The revision will be performed and documented using ENN procedure No. ENN-DC-147, "Engineering Reports". All new program reports and other documents which are not classified as calculations will be incorporated into the RIMS using ENN-DC-147. No new condition report is required.

### AFI2.2-3

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A review of program documents including PP 7028, the FAC Susceptibility Evaluation, the Small Bore Piping Database, and updates to the CHECWORKS models shows that updates have not been performed in timely manner. Some activities were informally performed with significant time elapsed without a formal revision.

### Consequences

Reliance on out of date information or documents which have not been formally updated, coupled with personnel turnover has resulted in discovering unexpected wear in plant piping and plant unavailability at other utilities. It is important to keep program information up to date.

Planned updates to the susceptibility report and the small bore database report only result in not formally documenting piping replacements performed since the last update. There is no adverse affects to the plant susceptibility, only on the timeliness of document updates. Timely updates to the CHECWORKS models are good practice. Given low wear rates from recent outage inspection data and nearly constant plant operating conditions, there is no immediate need for model updates. However operation under HWC and the planned power uprate warrant model revisions.

### Recommendation

An update to the FAC susceptibility evaluation, small bore data base, and the CHECWORKS models is currently on the EWC schedule. However, based on the amount of EPU related work, which has resulted in deferring completion of planned program activities, additional monitoring may be required. A separate Snapshot Assessment should be performed insure that these planned program activities were actually performed in a timely manner. The results of the assessment may identify the need to revise/improve existing scheduling/resources & trend performance.

Condition Report: LO-VTYLO-2003-00327 CA2

### AFI2.2-4

There is no formal method for Operations Dept to communicate changes in operating conditions, off-normal or abnormal system lineups to the FAC Program for assessment.

### Consequences

Changes in operating conditions, off-normal or abnormal system lineups, component leakage or operating experience are communicated, can affect FAC wear rates in piping and components. Information on off normal conditions is currently obtained through a review of site procedures, system health reports, thermal performance monitoring reports, Condition Reports, and site and industry operating experience. These tools assist in scoping lines for inspection or incorporating in the susceptible report. However the link with operations needs to be strengthened.

### Recommendation

## ENVY Design Engineering Self Assessment: LO-VTYLO-2003-00327

Develop formal method or protocol for Operations Dept to communicate changes in operating conditions, off-normal or abnormal system lineups to FAC Program for assessment.

Condition Report: LO-VTYLO-2003-00327 CA3

Objective 2.3 - Documentation - Ensure that FAC Documentation is in compliance with industry standards and that it is maintained in accordance with established processes and procedures.

### Conclusion

The FAC program procedure, PP 7028, and department procedure DP 0072, for Structural Evaluation of Thinned Wall Piping Components, and several component evaluations were reviewed. The documents were prepared by the FAG engineer and reviewed by the backup FAC engineer. NDE reports are reviewed and checked by a Level III examiner as well as by the FAG engineer. The program procedure and supporting procedures are consistent with NSAC 202L guidelines.

The program procedure was last changed in 2001. The FAG coordinator is aware that the procedure is in need for update and has identified updates and improvements in previous self assessments of the program. There are two existing commitments (LO-VTVLO-2002-00341 and LO-VTVLO-2002-00568) in place for specific additions/improvements to PP7028. This update should include not only update to the procedure content per the commitments as but also update and formalize the FAG isometric drawings which are part of the program procedure. AFI2.3-1

There are two procedure related issues related to the ENN transition. The gridding procedure has resided in the UT procedure (NE-8053) until recently, when NE-8053 was made obsolete by ENN-NDE-9.05 rev 0. This is not only an issue for VY but also for other ENN FAC programs. The new NDE procedure does not include FAC gridding guidelines that were once a part of the VY site procedure. The gridding procedure will be relocated into an Appendix in the FAC Program procedure. Existing commitment No. LO-VTVLO-2003-00528 is in place to relocate the component gridding guidelines.

VY has not adopted the new ENN procedure for wall thinning evaluations, ENN-DC-133 for their FAG program. Adoption of the new ENN procedure for VY is TBD. At this time VY still uses its plant specific procedure for evaluating wall thinning (DP 0072). Modification of DP0072 and conversion to ENN-DC-133 for wall thinning evaluations is required. AFI2.3-2.

A component inspection database for small bore component inspections is included in Appendix B of PP 7028, but is not up to date. The last revision was in December of 1999. An update of the small bore database is currently in the EWC schedule. See AFI 2.2-1. For large bore components, information and all inspection data to date has been included in the CHEGWORKS database. At this time CHEGWORKS is considered the main component database for large bore components.

Refueling Outage Inspection Reports for the last three refueling outages have been issued within 90 days of startup. The reports summarize the inspection activities performed, the goals that were planned and accomplished, and the inspection results. The reports also

## ENVY Design Engineering Self Assessment: LO-VTYLO-2003-00327

include recommendations for future replacements or repairs and future required monitoring. The reports are prepared by the FAC engineer and independently reviewed and signed.

FAC large bore piping component location sketches are located in Appendix A of PP 7028. The sketches identify the lines and components included in the CHECWORKS database and predictive models. Information on the component location sketches is consistent with the CHECKWORKS model and the component numbering system. The sketches reference P&IDs and pipe drawings used to develop drawings, but the FAC sketches can only be updated as a procedure update since they are part of the FAC program procedure.

The component location sketches are not included in the plant drawing list and are not controlled through configuration management. Specific sketches have not been updated to reflect recent material replacements. Revisions to the sketches are not controlled using the same configuration management same process as for P&IDs or plant piping drawings. It is recommended that the FAC component location sketches be updated, removed from the procedure, converted into plant drawings, and placed under configuration management control. This will ensure that they reflect current plant configuration including material changes. AFI 2.3-1.

### Areas for Improvement

#### AFI2.3-1

The FAC Component Location Sketches are contained in Appendix A of PP 7028. The practice at other ENN plants is that the "FAC Isometrics" are separate controlled drawings. Updating the FAC component location sketches, removing them from the procedure, and converting them into plant drawings placed under configuration management control will ensure that they reflect current plant configuration including material changes. A similar condition existed at VY for the plant fire barrier sketches. These were converted to VY plant drawings (8-191500 series). ENN FAC Program standardization will require converting the existing FAC Component Location Sketches to VY controlled drawings.

### Consequences

The component location sketches are not included in the plant drawing list and are not controlled through configuration management. Specific sketches are marked up pending a change to the Program Procedure. Since the document is not in the formal records management system the possibility of using outdated information with loss or personnel turnover exists.

### Recommendation

Update the FAC component location sketches to incorporate recent piping changes, remove them from the procedure, and convert them into plant drawings. This will ensure that they reflect current plant configuration including material changes. (Note: This is not a trivial effort. The electronic files are on an obsolete format. A previous effort with J. Fortier was made, with little success. Need to explore options /costs etc. )

Condition Report: LO-VTYLO-2003-00327-CA4



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### AFI2.3-2

VY has not adopted the new ENN procedure for wall thinning evaluations, ENN-DC-133 for their FAC program. Adoption of the new ENN procedure for VY is TBD. At this time VY still uses its plant specific procedure for evaluating wall thinning (DP 0072). There are incompatibilities and different focus area in these procedures. Modification of DP0072 and conversion to ENN-DC-133 for wall thinning evaluations is required for fleet standardization.

#### Consequences

There is no choice. VY will use ENN standard procedures. Technical concerns with use of ENN-DC-133 must be resolved.

#### Recommendation

Resolve technical issues with use of ENN-DC-133 in its current form and support procedure revision to be consistent with requirements from the new ENN FAC Program Procedure, ENN-DC-315.

Condition Report: LO-VTYLO-2003-00327 CA5

Objective 2.4 - Model Verification and Review - Ensure that FAC predictive computer model used (such as CHECWORKS) is verified, reviewed and maintained in accordance to the plant's FAC Program procedures.

#### Conclusion

CHECWORKS models and wear rate analyses for large bore systems are used at Vermont Yankee. A complete revision to all plant models was performed in 1996. These were prepared in-house and reviewed by FAC coordinator. Since 1996, only a limited number of models updates were performed to include additional inspection data and to evaluate FAC effects of operation under hydrogen water chemistry. Outage inspection plans consider both CHECWORKS Pass 1 & Pass 2 results for selecting components for inspection.

The CHECWORKS database has been updated with current operating hours (up to cycle 29) and heat balance parameters are current. All inspection data to date has been imported into the CHECWORKS database. There have been no significant chemistry changes performed at VY to date. The FAC coordinator is aware of future plant plans such as starting HWC and power uprate and will update CHECWORKS according when these plans are implemented.

A review of the CHECWORKS models for two lines was performed. The models included all piping components, contained the correct component identifiers, and reflected the correct geometry. All component information was found to be correct and verified by the heat balance and flow diagrams.

Updates to the CHECWORKS models wear rate analyses to include the latest inspection data were not formally documented and reviewed. Although updates were planned in the EWC schedule, this is considered a program weakness. AFI 2.4-1

#### Areas for Improvement

##### AFI2.4-1

Updates to the CHECWORKS models should be formally updated and reviewed.

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Consequences

The evaluations are not considered as formal plant calculations based on the classification of the EPRI software. CHECWORKS is used as an inspection planning tool. The results are statistically based and do (did) not fit the attributes required for calculations under AP 0017. The current CHECWORKS evaluations are internal program documents. The VY document system in place prior to becoming Entergy only assigned formal numbers to calculations. No system was in place to number or catalog "reports" other than through incorporation into the program of job files. Since the model updates are not in the formal records management system the possibility of obsolescence or loss with personnel turnover exists.

Recommendation

With adoption of ENN-DC-147 "Engineering Reports" and "ENN-DC-126" formal mechanisms is now available to perform, review and document the CHECWORKS model input and analysis updates. Review all program generated documents and incorporate them into RIMS per ENN-DC-126 or ENN-DC-147 as appropriate.

Condition Report: LO-VTYLO-2003-00327 CA6

Objective 2.5 -Inspection Planning - Ensure that FAC examination locations are selected in accordance with the site procedures and industry practices.

Conclusion

Program procedure PP 7028 Section 4.4.1 specifies the process for selecting components and Appendix E of PP 7028 defines the criteria for selection of components for inspection. This approach used is consistent with NSAC 202L R2 guidelines.

CHECWORKS Pass 1 analysis output is only used to exclude lines from the inspection selection process in terms of susceptible or not susceptible. Generally most of the inspection selections from the CHECWORKS output are from the Pass 2 analysis output. This is consistent with the NSAC 202L approach. However, CHECWORKS model updates to include recent inspection data have not been performed. See AFI 2.4-1.

The selection of inspection locations effectively considers known industry issues with piping downstream of flow control valves, turbine cross around piping, dissimilar metal connections. Examination locations consider input from other plant departments such as System Engineering (thermal performance monitoring), Chemistry, and the Operating Experience Coordinator.

The selection of components for inspection during a refueling outage is documented on worksheets titled "Inspection Location Worksheets/Methods and Reasons for Component Selection". These worksheets provide a rigorous and thorough method to aid in the identification and selection of components for inspection. The worksheets include all the selection criteria necessary for a thorough review of small bore, large bore, feedwater heater shells, and cross-around piping. The worksheets address inspections based on previous inspection results, CHECWORKS evaluations, CHECWORKS model calibration, OE, off normal flow conditions, malfunctioning equipment such as leaking valves, and engineering judgment. The worksheets are prepared by the program owner and reviewed by the backup FAC program Engineer. Components identified in the worksheets are compiled in the

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## ENVY Design Engineering Self Assessment: LO-VTYLO-2003-00327

Refueling Outage Scoping memo to Program Owners supervisor. The worksheets used to select inspections should be considered program strength. STR 2.5-1 It presents a thorough documented approach to inspection selection incorporating all the criteria in NSAC-202L, and site specific issues.

### Areas for Improvement

None identified for Objective 2.5

### Strengths

#### STR 2.5-1

The worksheets used to select inspections should be considered a program strength. The worksheets present a thorough, rigorous, documented approach to inspection selection incorporating all the criteria in NSAC-202L, and site specific issues.

Objective 2.6 - Performing Inspections - Ensure that FAC Examinations are performed in accordance with the site procedures and FAC Program documents and that they are consistent with industry standards.

### Conclusion

A review of program procedure PP 7028 and the applicable NDE procedures for Level 11/ supervision and compliance responsibilities was performed. The procedure specific instructions and guidance for performing FAC inspections are consistent with NSAC 202L Rev.2.

There is an issue related to the ENN transition. The gridding procedure has resided in the VY site UT procedure NE-8053. NE-8053 was made obsolete by ENN-NDE-9.05 rev 0. This is not only an issue for VY but also for other ENN FAC programs. The new NDE procedure does not include FAC gridding guidelines that were once a part of the VY site procedure. The gridding procedure will be relocated into an Appendix in the FAC Program procedure. EXisting commitment No. LQ-vrVLO-2003-00528 is in place to relocate the component gridding guidelines.

Several component inspection reports were reviewed and it was concluded that the gridding convention used (size & extent) is consistent with the requirements of NSAC 202L Rev.2 and industry standards.

Certification / qualification records for two FAC inspectors were reviewed and it was determined that the processing and review of the technicians qualification and certification records were conducted and accepted in accordance with plant protocol.

Data sheets were reviewed for evidence that repeat inspection of suspect readings is performed. Two inspections from the 2001 refueling outage demonstrated questioning of the data. One was at a counter-bore and the other at a suspect reading lower than the surrounding area. The documentation showed both readings were re-taken and new measurements replaced the previous ones.

## ENVY Design Engineering Self Assessment: LO-VTYLO-2003-00327

Program procedure PP 7028 was reviewed with particular reference to Sections 4.4.1.3 and 6.3 which require formal record retention. Interviewed FAC program owner for compliance and determined inspection records are retained in accordance with PP 7028.

### Areas for Improvement

None identified for Objective 2.6

Objective 2.7 Data Evaluation - Determine if the process for collecting, evaluating, analyzing and trending data is effective and is performed in accordance with established standards.

### Conclusion

The FAC program document, PP 7028 rev 1, refers to DP 0072 for evaluating components. Component evaluations are performed in accordance with plant procedure DP 0072, "Structural Evaluation of Thinned wall piping components. At this time, VY is not required to perform evaluations based on ENN-DC-133. Component evaluations are also consistent with industry procedure NSAC-202L R2.

DP 0072 is used to evaluate components for continued service or replacement and outlines a formal process to perform evaluations. Evaluations are not considered calculations but they are reviewed and signed by an independent reviewer and are permanently stored by records for plant lifetime. Safety class piping and components under ASME section XI requirements are dispositioned in accordance with DP 4027.

The 2000 Refueling Outage Report was reviewed for examples of component evaluations, specifically inspection No. 2000-04. The completed acceptance evaluation includes the component disposition, NDE reports, and structural evaluation which is documented on a Component Evaluation Worksheet. UT data is reviewed by Level III examiner and signed. The evaluations are independently reviewed. All worksheets are stored in records for plant lifetime. DP 0072 provides a formalized process, which includes criteria and data sheets, and the appropriate safety factors. It is found to be adequate for dispositioning components for continued service or replacement.

### Areas for Improvement

None identified for Objective 2.7

Objective 2.8 - Performing Repairs - Ensure that FAC Repairs/Replacements are performed in accordance with established processes, procedures and applicable codes.

### Conclusion

Formal procedures exist for repair/replacement. Safety class ASME section XI components are evaluated and dispositioned under DP 4027, and component repairs / replacements are performed under AP 0070. Non-safety repairs/replacements would be controlled via maintenance work orders for like-for-like replacements. For upgraded material replacements, an engineering recommendation, followed by an equivalency evaluation and either a WOSE Minor Mod per AP 0020 or a design change per AP 6008 is required to implement the replacement. AP 0070 "ASME Section XI Repair and Replacement Procedure" provides a

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## ENVY Design Engineering Self Assessment: LO-VTYLO-2003-00327

formal process, that is consistent with the requirements of ASME Section XI and NSAC-202L-R2.

All external weld repairs are considered temporary, are performed using approved procedures, and require approval from the ANII. These are either permanently repaired or replaced during the next opportune time or refueling outage. External repairs to Safety Class Piping would require a relief and would be performed under the requirements of AP 0070, "ASME Section XI Repair and Replacement Procedure". To date no external repairs to Safety Class piping due to FAC related damage have been performed at VY.

Internal weld repairs on non Safety Class piping are considered permanent, are performed using approved procedures, and require approval from the ANII. Internal weld repairs to Safety Class Piping are performed under the requirements of AP 0070, "ASME Section XI Repair and Replacement Procedure" using approved welders and welding procedures. This is consistent with ASME Section XI and NSAC-202L-R2 guidelines.

Equivalency evaluations, engineering recommendations, and mod packages for material upgrades due to FAC are reviewed and approved prior to installation in the plant. Replacement of FAC susceptible systems with Cr-Mo (P11 or P22) is common knowledge plant-wide and is not stated in FAC program procedure. All material changes are shown on system P&IDs. PP 7028 does not identify a specific process or procedure to be used when making a material upgrade. After the FAC engineer determines that a material upgrade is required, the Design Engineering Group performs the required evaluations and develops the modification packages using the standard design processes provided by AP 0020, and AP 6008.

### Areas for Improvement

None identified for Objective 2.8

Objective 2.9 • Long Term Strategy - Determine if the FAC Program has a long-term strategy that is consistent with the guidance provided in EPRI guideline NSAC-202L-R2, "Recommendations for an Effective FAC Program".

### Conclusion

VY is a BWR which has limited chemistry options for reducing FAC. The most effective long term method for reducing FAC wear is replacements with FAC resistant materials. VY has been vigilant on replacing susceptible systems with FAC resistant materials in order to reduce FAC long term. Areas that have been replaced include Moisture Separator Drain lines downstream of level control valves, feedwater flush and pump bypass lines downstream of normally closed valves on piping leading to the condenser, turbine cross around piping, small bore steam drain lines to the condenser, both LP turbine casings, all LP feedwater heaters.

Other systems and such as feedwater heater vents and the HP feedwater heaters are planned for replacement with FAC resistant material due to the 20% power uprate. These replacement efforts are the primary focus on reducing wear rates at VY and are consistent with NSAC-202L guidelines.

The FAC coordinator is aware of future plant plans such as starting HWC and power uprate and will update the CHECWORKS predictive models as these plans are implemented. Since VY is a BWR, there is very little that can be done to reduce FAC wear rates through water

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## ENVY Design Engineering Self Assessment: LO-VTYLO-2003-00327

chemistry changes. Dissolved oxygen in the final feedwater has been maintained in the 20 to 30 PPB range from 1996 to 2003. Future plans to start HWC will affect chemistry and will have to be monitored by the program.

The FAC program documentation was reviewed to ensure there is a process in place for informing FAC engineer of system changes that may effect FAC susceptible systems and that the effects of these changes to FAC are considered by appropriate department prior to making modifications to FAC susceptible systems and to ensure that replacements performed under the FAC program are communicated to system engineering (as well as other related departments) and appropriate drawings are updated with new material changes. Since the VY FAC Coordinator is part of the Design Engineering Group, he has direct access to information on system changes such as modifications and replacements being developed that may affect FAC susceptible systems. This is considered a strength of the program. STR 2.9-1

VY does not have a planned replacement goal for the next three to five years. Replacements have been based on current need. Also many piping systems which would have been found to be highly susceptible to FAC were originally design with resistant materials or have already been replaced with FAC Resistant materials. VY has made a conscious effort to replace piping systems and components that are susceptible with FAC resistant materials.

The ongoing effort of replacing systems with FAC resistant materials has reduced the amount of inspections performed during refueling outages. On average the number of inspections performed is around 20 to 30 piping components which is far below the average of typical plants. This is seen as a program strength. STR 2.9-2.

### Areas for Improvement

None identified for Objective 2.9

### Strengths

#### STR 2.9-1

The VY FAC Program Coordinator and the backup engineer are part of the Design Engineering Group. They have direct access to information on system changes such as modifications and replacements being developed that may affect FAC susceptible systems.

#### STR 2.9-2

The ongoing efforts of replacing piping with FAC resistant materials, has allowed a reduction in the number of inspections required to be performed during refueling outages. On average, around 20 to 30 piping components are inspected per refueling outage. This is less than the typical number of inspections performed for similar plants.

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## ENVY Design Engineering Self Assessment: LO-VTYLO-2003-00327

### 5.0 REFERENCES

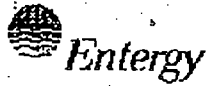
- ENW Commitment LO-VTYLO-2003-00327 (VY AP0028 No. OPW-2003-0161\_01), Conduct a Focused Self-Assessment of ENW Piping FAC Inspection Program, PP 7028.
- ENW Self Assessment No. OPW-2003-0145\_01 Assessment Planning Worksheet
- INPO "Principles for Self-Assessment and Corrective Action Programs", December 1999
- EPRI NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program", Final Report, April 1999.
- INPO 97-002, "Performance Objectives and Criteria for Operating Nuclear Generating Stations"
- INPO 03-004 (Preliminary) "Performance Objectives and Criteria"
- EPRI CHUG White Paper No.3, "A Summary of Tasks and Resources Required to Implement an Effective FAC Program", February 1999.
- USNRC Inspection Manual- Inspection Procedure 49001
- EPRI/Altran Report No. 95217-TR-01 Rev.O, "Guideline for Interviewing Plant Personnel within a FAC Program", August 1996.
- ENN-L1-104 Rev.4 , "Self Assessment & Benchmarking Process"
- Vermont Yankee Program Procedure PP 7028, "Piping FAC Inspection Program"
- Vermont Yankee Department Procedure DP 0072 "Structural Evaluation of Thinned Wall Piping Components"
- EPRI CHECWORKS Computer Program Users Guide TR-03496
- EPRI CHECWORKS "FAC Application Guidelines for Plant Modeling and Interpretation of Inspection Data", Draft Report, February 1997.
- ENN-DC-133 "Structural Evaluation of Wall Thinning in Carbon and Low Alloy Steel Piping"

### 6.0 TEAM MEMBERS

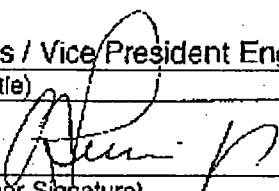
Team Leader: James Fitzpatrick*	V.Y. FAC Program Coordinator
Team Member: Hazel Pearsall	I.P.2 FAC Program Coordinator
Team Member: Harry Hartjen	I.P.3 FAC Program Coordinator
Team Member: Ian Mew	J.A.F. FAC Program Coordinator
Team Member: Gerald Bechen	Pilgrim FAC Program Coordinator
Team Member: John Moriarty**	C.A.&A (VY)**

\* The Team Leader completed the Team Leader Checklist on completed 8/5/03.

\*\* CA&A representative reviewed then Assessment Plan ,but was called to military duty prior to the assessment.

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Flow Accelerated Corrosion Program				

Title: Flow Accelerated Corrosion Program

Procedure Owner:	Oscar Limpas / Vice President Engineering	
	(Print Name / Title)	
Approved:		3/09/06
	(Procedure Owner Signature)	(Date)

Effective Date	EN Common	<input type="checkbox"/>	Effective Date Exception	ANO		PNPS	
	ENN	<input checked="" type="checkbox"/>		ECH		RBS	
	ENS	<input type="checkbox"/>		GGNS		VY	
				IPEC		W3	
				JAF		WPO	

Procedure Contains NMM REFLIB Forms: YES ☐ NO ☐

**Basis Statement**

Re-defined Significant wall thinning  
 Deleted superseded procedure ENN-DC-133 from text and replaced with ENN-CS-S-008.  
 Added EPRI CHUG position Paper No.4 to references  
 Added "CHECWORKS Steam /Feedwater Application, Guidelines for Plant Modeling and Evaluation of Component Inspection Data to references.  
 Added Passport to text in section 4.4.11.  
 Added "degraded and deficient" components to text of section 4.4.16  
 Added threshold for generating condition reports to section 5.11.3  
 Added "except as provided below" and "Reference section 5.12.2" to section 5.12.1.  
 Added text "and it is determined that sample expansion" to section 5.12.2.  
 Added "deficient" to section 5.13.1  
 Edited various typos to section 8.  
 Edited logic diagram in attachment 9.3.  
 Re-indexed section 5.2 to 5.17  
 Add VY to ENN Fleet procedure.

This procedure supersedes the following site procedures:

- ENN DC-315 Rev.0
- VY - PP7028

**Site and NMM Procedures Canceled or Superseded By This Revision**

ENN-DC-315 Rev.0

**Process Applicability Exclusion (ENN-LI-100) / Programmatic Exclusion (ENS-LI-101)**

All Sites: ☐ Specific Sites: ANO ☐ GGNS ☐ IPEC ☐ JAF ☐ PNPS ☐ RBS ☐ VY ☐ W3 ☐





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Flow Accelerated Corrosion Program

## 1.0 PURPOSE

- [1] The purpose of this procedure is to provide requirements for establishing and maintaining an effective Flow Accelerated Corrosion (FAC) Program that will standardize Entergy Nuclear Northeast Fleet's approach towards mitigating FAC damage.
- [2] This procedure uses a systematic approach for long term monitoring to enhance the reliability of the affected FAC components by reducing the probability of failures and reduces maintenance costs associated with unplanned or unnecessary repairs.
- [3] This procedure provides criteria and methodology for selecting components for inspection, performing inspections, gridding, evaluating Inspection data, disposition of results, sample expansion requirements, piping repair /replacement criteria, program responsibilities and documentation requirements.
- [4] This program is applicable to plant piping systems and feed water heater shells susceptible to FAC.
- [5] This procedure may be used a guide for evaluating systems and components that don't meet the criteria of the FAC program.

## 2.0 REFERENCES

- [1] NRC Generic Letter 89-08, Erosion/Corrosion Induced Pipe Wall Thinning.
- [2] NUREG-1344, "Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants."
- [3] NSAC 202L, latest revision, EPRI Document, "Recommendations for an Effective Flow Accelerated Corrosion Program"
- [4] EPRI Technical Report, TR-106611, "Flow-Accelerated Corrosion in Power Plants"
- [5] NRC Bulletin No. 87-01, "Pipe Wall Thinning."
- [6] ENN-LI-102, "Corrective Action Process."
- [7] EPRI CHECWORKS FAC Application User's Guide/ CHECWORKS computer models.
- [8] ENN-NDE-9.05, "Ultrasonic Thickness measurement"
- [9] ANSI B31.1 "Power Piping", (For applicable code year see individual plant FSAR).
- [10] ENN-DC-126, "Calculations".



## Flow Accelerated Corrosion Program

- [11] ENN-CS-S-008, "Pipe Wall Thinning Structural Evaluation".
- [12] Site ASME XI Repair / Replacement Program as applicable.
- [13] ENN-EP-S-005 "Flow Accelerated Corrosion Component Scanning and Gridding Standard".
- [14] EPRI Report, "Single-Phase Erosion/Corrosion of Carbon Steel Piping", February 1987.
- [15] EPRI Report - "Practical Consideration for the Repair of Piping Systems Damaged by Erosion/Corrosion", dated 10/5/87
- [16] NRC Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repairs of ASME Code Class 1, 2 & 3 Piping".
- [17] INPO SOER 87-3, "Piping Failures in High-Energy Systems Due to Erosion/Corrosion", March 1987.
- [18] INPO Significant Operating Experience Report (SOER) 82-11, "Erosion of Steam Piping and Resulting Failure", February 1982.
- [19] EPRI CHUG Position Paper #3, "A Summary of Tasks and Resources Required to Implement an Effective Flow Accelerated Corrosion Program."
- [20] Entergy Quality Assurance Manual
- [21] ENN FAC Qualification Card ENN-TK-ESPG-042, "Implementing the Flow Accelerated Corrosion Program".
- [22] JAF-SPEC-MISC-03290 Rev.0, "Specification for Evaluation and Acceptance of Local Areas of material, parts and components that are less than the specified thickness." By REEDY Engineering.
- [23] IP3-SPEC-UNSPEC-02996 Rev.0, "Specification for Evaluation and Acceptance of Local Areas of material, parts and components that are less than the specified thickness." By REEDY Engineering.
- [24] EPRI CHUG Position Paper No. 4, "Recommendations for Inspecting Feedwater Heater Shells for Flow Accelerated Corrosion Damage", February 2000.
- [25] "CHECWORKS Steam /Feedwater Application, Guidelines for Plant Modeling and Evaluation of Component Inspection Data", EPRI No. 1009599, Final Report, September 2004.



### 3.0 DEFINITIONS

- [1] Base Line Inspection – An initial wall thickness measurement of a component taken prior to being placed in service.
- [2] Basis Document - Program documents that define the scope, attributes, commitments, evaluation reports and predictive models that forms the basis of the FAC program (i.e., System Susceptibility Evaluation reports). These documents contain the basis for the plant piping in the CHECWORKS model, the susceptible-not-modeled (SNM) piping and those that are non-susceptible.
- [3] EPRI CHUG – EPRI CHECWORKS USERS GROUP.
- [4] Code Minimum Thickness ( $T_{min}$ ) – The minimum required global wall thickness based on hoop stress.
- [5] Critical Thickness ( $T_{crit}$ ) - The minimum required wall thickness per code of construction required to meet all design-loading conditions.
- [6] Deficient Component - A component identified by examination to be below  $T_{acct}$  wall thickness or projected to be below  $T_{acct}$  wall thickness by the next refueling outage.
- [7] Degraded component – A component identified as being below the screening criteria that is acceptable for continued operation.
- [8] Examination - Denotes the performance of all visual observation and nondestructive testing, such as radiography, ultrasonic, eddy current, liquid penetrant and magnetic particle methods.
- [9] Examination Checklist/ Traveler – A data sheet developed for the components being inspected and may contain but is not limited to the following:  $T_{nom}$ ,  $T_{meas}$ ,  $T_{min}$ , Screening criteria, components name, system number, previous data, inspection datasheet number, grid size, examination extent, work order and affiliated minimum wall calculation.
- [10] Flow Accelerated Corrosion (FAC) - Degradation and consequent wall thinning of a component by a dissolution phenomenon, which is affected by variables such as temperature, steam quality, steam/fluid velocity, water chemistry, component material composition and component geometry. Previously known as Erosion/Corrosion.
- [11] Grid - A pattern of points or lines on a piping component, where UT thickness measurements will be made. Grid may be permanently marked with circumferential and longitudinal grid lines.



- [12] **Grid Point** – A Specific location on a piping component, where a UT thickness measurement will be made. Grid points are at the intersections of the circumferential and longitudinal grid lines.
- [13] **Grid Point Reading** – UT reading taken at the intersection of the grid location.
- [14] **Grid Scan**– 100% scan of the area between the grid lines. The lowest measurement in each area to be recorded as the measured thickness.
- [15] **Grid Size** - The distance between grid points in the circumferential or longitudinal direction. Also called grid space or grid spacing.
- [16] **Initial Thickness (Tinit)**: The thickness determined by ultrasonic examination prior to the component being placed into service (baseline) or the first ultrasonic examination during its service life. If an examination has not previously been performed on the component, the initial thickness shall be determined by reviewing the initial ultrasonic data for that component. The area of maximum wall thickness within the same region as the worn area shall be identified and compared to Tnom. If the thickness is greater than Tnom, the maximum wall thickness within that region shall be used as Tinit. If that thickness is less than Tnom, Tnom shall be used as Tinit. Initial thickness for pipe may also be calculated as the nominal thickness multiplied by a factor of 1.125 ( $1.125 \cdot Tnom$ ) for conservatism.
- [17] **Inspection Location** - A specific component (i.e., elbow, tee, reducer, straight pipe section).
- [18] **Inspection Outage** - the outage during which the component was inspected.
- [19] **Large-bore Piping** - Piping generally greater than 2" nominal pipe size with butt-weld fittings.
- [20] **Line Scans**– piping segments broken into one-foot lengths (Small-Bore pipe).
- [21] **Minimum acceptable wall thickness (Taccept)** – Maximum value of Tmin or Tcrit.
- [22] **Minimum Measured Thickness** - (Tmeas or Tmin) as identified by ultrasonic thickness examination, the present thickness at the thinnest point on a component.
- [23] **Minimum required thickness** – (Talloc) Minimum required pipe wall thickness for internal pressure based on local thinning requirements.
- [24] **Next Scheduled Inspection (NSI)** -The outage at which an inspection will be performed on a given component.
- [25] **Nominal Thickness (Tnom)** - Wall thickness equal to ANSI standard thickness.



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- [26] PASS 1 Analysis - Runs modeled in CHECWORKS that either have no inspection data, an insufficient number of inspections to provide a proper calibration, or where there is no expectation of ever developing a proper calibration.
- [27] PASS 2 Analysis - The process of utilizing UT inspection data thickness measurements in CHECWORKS to predict wear and wear rates for components.
- [28] Piping Segment - A run of piping that consists of inspection locations which have common operating parameters (i.e., temperature, pressure, flow rate, Oxygen content and pH level).
- [29] Predicted Thickness ( $t_p$ ,  $T_{pred}$ ) - The calculated thickness of a component based upon a rate of wear to some point in time (e.g., next refueling, next scheduled examination).
- [30] Quadrant Scan - Piping segments divided in quadrants A, B, C, D that are 90 degrees apart and broken into one-foot lengths, or as specified by the FAC engineer.
- [31] Qualified FAC Engineer - Individual who has completed the FAC Qualification Card, who participates in the Engineering Support Personnel (ESP) training program and demonstrates knowledge required for the use of the CHECWORKS computer program.
- [32] Reference Point - The point on a piping component where the longitudinal and circumferential grid lines originate.
- [33] Remaining Service Life (RSL) - The amount of time remaining based upon an established rate of wear at which the component is anticipated to thin to  $T_{acpt}$ .
- [34] Safety Factor - A Margin of Safety used to account for inaccuracies in wear rate evaluation.
- [35] Sample Expansion - The addition of inspection locations based on significant or unexpected wall thinning during planned inspection(s).
- [36] Significant wall thinning - Wall thinning to a thickness less than 60% of pipe nominal wall thickness or wall thinning to a thickness that is half the remaining margin of the piping /component which is above  $T_{acpt}$ . [ $\frac{1}{2} (0.875T_{nom} + T_{acpt})$ ] or ( $T_{acpt} + 0.020$ ) which ever is greater.
- [37] Small-bore Piping - Piping that is generally 2" or less nominal diameter and that typically uses socket welded fittings.
- [38] Subsequent Inspection - Inspection of components that have had a baseline inspection and/or an initial operational inspection.



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- [39] Susceptible Line - Piping determined to be susceptible to FAC using the EPRI susceptibility criteria in NSAC 202L, industry experience and as documented in the System Susceptible Evaluation.
- [40] Susceptible Non-Modeled (SNM) Piping - A subset of the FAC susceptible lines that cannot be modeled using the EPRI CHECWORKS software.
- [41] Time - Time in service shall be actual hours on line or of operation and/ or hours critical. Calendar hours may be used for conservatism.
- [42] UT Datasheets - Paperwork that documents the results of the ultrasonic thickness inspections.
- [43] Wear (W) - The amount of material removed or lost from a components wall thickness since baseline or subsequent to being placed in service.
- [44] Wear Rate (WR) - Wall loss per unit time.

#### 4.0 RESPONSIBILITIES

##### 4.1 MANAGER, ENGINEERING PROGRAMS (ENNE FLEET PROGRAM OVERSIGHT)

- [1] Providing a single point of accountability and is responsible for the overall health and direction of the FAC programs.
- [2] Ensuring that the ENN FAC programs are effectively developed and implemented.
- [3] Providing oversight for implementing the FAC programs.
- [4] Co-ordinate FAC working group meetings.
- [5] Co-ordinate ENN FAC Self-Assessments.

##### 4.2 SUPERVISOR, CODE PROGRAMS

- [1] ~~Designate responsible engineer/~~Personnel from the Code Programs Engineering Group for the implementation and maintenance of the Flow Accelerated Corrosion Program.
- [2] Ensure that the Flow Accelerated Corrosion Program activities are conducted in accordance with this procedure.
- [3] Shall ensure that repair procedures are in place to support any planned repairs or replacements.



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- [4] Ensure audits and surveillance of selected Flow Accelerated Corrosion (FAC) activities are performed to verify compliance with applicable codes, procedures and drawings.
- [5] Provides personnel to perform NDE during normal plant operation and unscheduled outages.
- [6] Shall provide qualified Non-Destructive Examination personnel to perform flow accelerated corrosion inspections during scheduled refueling and maintenance outages.
- [7] Provides personnel to perform reviews of all final FAC UT data sheets.
- [8] Provides personnel to review vendor procedures, personnel certifications and equipment certifications.
- [9] Assuring adequate technical personnel are available to provide required support services prior to the outage.

#### 4.3 NDE LEVEL III OR DESIGNEE

- [1] Reviews and approves FAC personnel and equipment certifications, and NDE procedures including revisions.
- [2] NDE Level II or Level III reviews and signs all final FAC UT data sheets to ensure appropriate NDE examinations have been completed in accordance with the FAC program. The NDE level III review of Risk Informed examination shall be performed in accordance with the site ISI program requirements.
- [3] Resolution of anomalies found in inspection data.
- [4] Identify discrepancies or deficiencies and initiates condition report in accordance with FAC program or site protocols as appropriate.
- [5] Performs oversight of selected FAC examinations to verify vendor procedure compliance.
- [6] Performs functions in accordance with applicable procedures including the Entergy Quality Assurance Program.

#### 4.4 FLOW ACCELERATED CORROSION ENGINEER

- [1] Shall determine scope of inspections. The FAC Engineer shall develop a list of components/piping segments to be inspected prior to each outage using the criteria of NSAC-202L and CHECWORKS Pass1 and Pass 2 output as a guide. Previous





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outage inspection results shall be reviewed prior to development of the inspection list. This list shall be based on the susceptibility to flow accelerated corrosion and the severities of wear identified from previous inspection results.

- [2] Review and/or perform an engineering evaluation for all Flow Accelerated Corrosion inspections where pipe wall thinning has been identified and concur on any recommended action. Calculations shall be done in accordance with ENN-DC-126 & ENN-CS-S-008.
- [3] Shall ensure that appropriate inspections are performed in accordance with the scope of the Flow Accelerated Corrosion Program.
- [4] Shall review and may sign all inspection data and make recommendations for repair/replacement of piping materials in accordance with applicable site protocols.
- [5] Shall provide NDE data for review and signature to the ANII, if requested by the ANII.
- [6] Shall provide Risk Informed Inspection to the ANII for review and signature, if applicable.
- [7] Develops or reviews program basis documents.
- [8] Shall revise and/or expand the scope of the Flow Accelerated Corrosion inspection program to incorporate industry and in-house experiences and track/trend inspection results.
- [9] Shall maintain records of all inspection results and inspection database.
- [10] Develop a FAC examination checklist/traveler that contains Tnom, screening criteria, Taccpt, line number, etc. for the components being inspected.
- [11] Shall initiate request for engineering services in accordance with the MAXIMO/PASSPORT or site specific work control system for piping replacement or engineering evaluations as required. This request should include recommended materials for replacement and configuration changes, if applicable, to reduce the effects of flow accelerated corrosion.
- [12] The FAC Engineer shall periodically review completed plant modifications to assess their effect on the scope of the flow accelerated corrosion program.
- [13] The FAC Engineer shall assist in vendor oversight as required.
- [14] Maintaining control of the predictive models (CHECWORKS), which includes any development, updates or revisions to the models.



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- [15] Developing, revising, and issuing FAC program documents.
- [16] Initiating and/or responding to Condition Reports and Engineering Requests for evaluating degraded and deficient components or other discrepancies or deficiencies within the scope of the FAC program.
- [17] Developing post outage inspection summary reports.
- [18] Review and disposition Operating Event (OE) notices for applicability to the FAC program.
- [19] Analyzing inspection data to determine component acceptability for continued service and to determine the need for sample expansion.
- [20] Prioritizing and ranking inspection in terms of susceptibility and consequence of failure.
- [21] Develop and maintain the System Susceptibility Evaluation report.

4.5 DESIGN ENGINEERING/RESPONSIBLE ENGINEER

- [1] Provide minimum acceptable wall thickness ( $T_{accpt}$ ) to the FAC Engineer. Responsibility may be delegated to another department or qualified personnel.
- [2] Perform local wall thinning evaluations for components having UT measurements that are below or are projected to go below the minimum acceptable wall thickness ( $T_{accpt}$ ) or administrative wall thickness requirement.
- [3] Prepare and issue engineering response packages for component requiring replacement. Responsibility may be delegated to another department or qualified personnel.
- [4] Perform remaining service life evaluation for components in the FAC program as required.

4.6 MAINTENANCE SUPERVISOR/DESIGNEE

- [1] The maintenance supervisor or designee will ensure that adequate craft personnel are available to support the FAC program. The supervisor shall ensure that scaffolding is erected, when needed, and insulation removed from components/piping segments that will be inspected and that the piping is prepared for inspection. Scaffolding erection in safety related areas should be in accordance with site procedures.



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- [2] The maintenance supervisor or designee shall inform the FAC engineer when it is necessary to remove a pipe support for inspection. An engineering evaluation is required if a pipe support requires removal.
- [3] The maintenance supervisor must ensure that surfaces to be inspected are free from all foreign materials that would interfere with the inspections, i.e., dirt, rust, paint, etc. If cleaning is required, this may be accomplished by power sanding, flapper wheel only) hand wire brushing, or hand sanding in accordance with site procedures/protocols.
- [4] The maintenance supervisor shall ensure restoration of lines, i.e. insulation replaced, scaffolding removed, upon completion of the FAC inspection.

#### 4.7 FAC INSPECTION COORDINATOR

- [1] A FAC coordinator may be chosen to implement the activities of the inspection plan, the duties may include but is not limited to the following activities:
  - (a) Performing component walk downs
  - (b) Generating NDE inspection packages
  - (c) Defining NDE staffing as required
  - (d) Scheduling of inspections
  - (e) Acquiring data as required
  - (f) Providing field coordination to ensure timely inspection are accomplished
  - (g) Tracking progress of the FAC inspection project
  - (h) Transmitting inspection results to the FAC Engineer

#### 5.0 DETAILS

##### 5.1 PRECAUTIONS AND LIMITATIONS

None.

##### 5.2 ANALYSIS/PRE-EXAMINATION

- [1] The criteria contained in NSAC-202L, latest revision, shall be used to perform the System Susceptibility Evaluation (SSE).



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- [2] The System Susceptibility Evaluation report shall be developed and peer checked in accordance with ENN procedures.
- [3] Non-typical operation of systems should be taken into consideration and if necessary factored into the FAC program.
- [4] The susceptible small-bore piping inspection priority ranking should consider personnel safety, consequence of failure and plant unavailability.
- [5] Industry and plant experiences relating to FAC will be factored into the program.
- [6] The CHECWORKS model should be used for guidance in determining inspection priority based on relative ranking for specific locations to be examined for FAC damage.

### 5.3 PREPARATION OF OUTAGE INSPECTION PLAN

- [1] The FAC Program Engineer shall prepare an Outage Inspection Plan prior to the outage to meet site milestones.
- [2] The Outage Inspection Plan should consider the cost of repair/replacement versus inspection.
- [3] The Outage Inspection Plan should consider inspection priority based on relative ranking for specific locations to be examined for FAC damage.
- [4] Each identified location shall be documented in the inspection plan, along with the component number and reason for selection.
- [5] The inspection plan shall be reviewed.
- [6] Component Selection
  - (a) The FAC engineer shall prepare a FAC Outage Inspection scope as directed by plant milestones or as directed by Station management.
  - (b) Inspection selections shall be made in accordance with the requirements of this procedure and shall be identified based on CHECWORKS results, industry/station/utility experience, required re-inspections, the non-modeled program piping and engineering judgment.
  - (c) If a selected inspection location is determined to be excessively difficult, impractical or costly to examine due to inaccessibility, temperature, ALARA concerns, scaffolding requirements, or other factors, then an equivalent alternate inspection location may be selected.



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- (d) Components selected shall be formally documented.
- (e) The criteria for component selection should consider the following:
  - (1) Components selected from measured or apparent wear found in previous inspection results.
  - (2) Components ranked high for susceptibility from current CHECWORKS evaluation.
  - (3) Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.
  - (4) Components selected to calibrate the CHECWORKS models.
  - (5) Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system.
  - (6) Engineering judgment / Other
  - (7) Piping identified from Work Orders (malfunctioning equipment, leaking valves, etc.).
  - (8) Susceptible piping locations (groups of components) contained in the Small Bore Piping database, which have not received an initial inspection.
  - (9) Piping identified from Condition Reports/ Corrective action, Work Orders (malfunctioning equip, leaking valves, etc.).
  - (10) Feed water Heater Shells

[7] Inspection schedule

- (a) Inspection sequence and schedule should be developed based on priority established by the FAC engineer considering repair/scope expansion potential. Consideration will also be incorporated based on other outage work priorities, job conflict and system window duration.
- (b) The FAC outage schedule should contain sufficient time for analysis and evaluations of the components being inspected.

[8] Drawing Preparation



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- (a) For each component scheduled for inspection, an isometric or other acceptable location drawing should be prepared prior to the outage that identifies the component to be examined. When applicable ensure the component number is shown on the drawing.
- [9] Obtain Minimum Acceptable Wall Thickness (Taccpt)
  - (a) Obtain Taccpt (maximum of Tmin or Tcrit) values for each component to be inspected. Those values may be obtained as required, prior to or during an outage.
  - (b) These criteria may be obtained from engineering calculations or by other approved methods.
- [10] Component Identification
  - (a) Inspected components should have a unique identifier to allow for the tracking of inspection data.
  - (b) Component identifiers may allow for the identification of the Unit, system, sub-system, line number and corresponding location of that component within a sub-system.
  - (c) Components in the CHECWORKS non-modeled piping may be identified by using line numbers.
- [11] Pre-Inspection Activities
  - (a) Review inspection schedule, inspection requirements and sequence with appropriate plant personnel to ensure requirements for the completion of the FAC inspection are understood.
  - (b) The FAC engineer should participate in the preparation of FAC inspection work packages as required.

#### 5.4 GRIDDING

- [1] Gridding of components shall be performed in accordance with recommendation of NSAC 202L, ENN-EP-S-005 or as specified by the FAC engineer.
- [2] Gridding information shall be documented on the appropriate NDE UT data sheet; a sketch may also be required.



## **5.5 NDE TEST METHODS AND DOCUMENTATION**

- [1] Components can be inspected for FAC wear using ultrasonic testing (UT), radiography testing (RT), visual observation or other approved methods.**
- [2] UT thickness measurement is the primary method of determining pipe wall thickness.**
  - (a) Inspections will be performed by using one of the following techniques:**
    - (1) Grid Point Reading**
    - (2) Grid Scan**
    - (3) Quadrant Scan**
    - (4) Line Scan**
- [3] Ultrasonic Thickness measurement shall be performed in accordance with ENN-NDE-9.05 or other approved site or vendor procedures.**
- [4] UT Data sheets**
  - (a) A data sheet for components inspected shall be prepared. The information included in the sheet should contain but is not limited to the following:**
    - (1) Plant's name/unit**
    - (2) Components name**
    - (3) Component sketch**
    - (4) NDE technician signature/ date**
    - (5) Grid size**
    - (6) Axial and radial grid boundaries**
    - (7) Calibration information**
    - (8) Level II or Level III signature/date**
    - (9) Work order information**
    - (10) Nominal & Measured thickness**
    - (11) 87.5% nominal thickness screening criteria**



(12) Scanning method

5.6 EVALUATION OF UT INSPECTION DATA

NOTE

Historically, typical manufacturing practice has been to supply fittings (especially tees, elbows and reducers) with wall thickness significantly larger than the piping nominal thickness.

- [1] The data review should consider screening for further evaluation. Factors that should be considered when reviewing the inspection data include unknown initial thickness (especially fittings), counter-bore, obstructions, and manufacturing wall thickness variations.
- [2] For each component that is examined and is below the screening criteria of 87.5% of nominal wall, the wear, wear rate, remaining service life shall be calculated.
- [3] The FAC Program Engineer or designee shall review the UT data to ensure that the data is complete and corresponds to the requirements specified on the inspection data sheet (i.e., grid size, spacing, flow direction, starting and ending locations, obstructions, missing data, suspect readings and orientation).
- [4] If low readings are determined from repeat inspections that are due to counter-bore, then those areas shall be noted and additional inspections are not required.
- [5] Grid Refinement
  - (a) A grid reduction / refinement may be used if the minimum measured thickness is less than the minimum required wall thickness, severe wall thinning is detected, engineering judgment, or the projected thickness is less than the minimum required wall thickness or as directed by the FAC engineer.
  - (b) The results of the grid refinement or scan shall be documented on an inspection data sheet.
- [6] Grid Extension
  - (a) If measurement indicates wall loss at either edge of the grid, then the grid should be extended until the entire wear pattern is mapped.
- [7] Determination of Initial Wall Thickness
  - (a) For fittings, the band, area and blanket methods calculate wear. Initial Thickness (T<sub>init</sub>): The thickness determined by ultrasonic examination prior to





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the component being placed into service (baseline) or the first ultrasonic examination during its service life. If an examination has not previously been performed on the component, the initial thickness shall be determined by reviewing the initial ultrasonic data for that component. The area of maximum wall thickness within the same region as the worn area shall be identified and compared to  $T_{nom}$ . If the thickness is greater than  $T_{nom}$ , the maximum wall thickness within that region shall be used as  $T_{init}$ . If that thickness is less than  $T_{nom}$ ,  $T_{nom}$  shall be used as  $T_{init}$ .

- (b) Initial thickness for pipe may be calculated as the nominal thickness multiplied by a factor of 1.125 ( $1.125T_{nom}$ ) for conservatism.

[8] Determination of Wear

- (a) Wear of piping components may be evaluated using the band, area, blanket or point-to-point method as defined in NSAC-202L, latest revision.
- (b) Evaluation of inspection data that is determined to require wear evaluation shall be documented and reviewed.

[9] Wear rate Determination

- (a) Wear rate is determined by wear/ unit time (Units to be consistent with thickness evaluation).
- (b) A reasonable safety factor may be applied to the wear rates to account for inaccuracies in the FAC wear rate calculations.
- (c) Wear rate evaluation should be evaluated on a component evaluation sheet.

[10] Predicted Thickness ( $t_p$ ,  $T_{pred}$ )

- (a) The projected or predicted thickness to the next schedule refueling outage.

$$T_{pred} = T_{meas} - \text{Safety factor} \times \text{Wear Rate} \times \text{Time}$$

A safety factor of 1.1 may be applied to ENN plants. If a value other 1.1 is used the reason shall be documented.

[11] Determination of Remaining Service Life (RSL)

- (a) Remaining service life (RSL) shall be evaluated as follows, units to be consistent with thickness evaluation:

$$RSL = (T_{meas} - T_{accpt}) / (\text{Safety Factor} \times \text{Wear Rate})$$



## 5.7 EVALUATION OF RT INSPECTION DATA

- [1] Qualified NDE personnel shall interpret the film and report the examination result to the FAC engineer.
- [2] Appropriate conservatism should be used to determine if a component requires replacement or re-inspection as a consequence of qualitative nature of RT.
- [3] RT inspection shall be recorded on a data sheet.

## 5.8 EVALUATION OF VISUAL INSPECTION DATA

- [1] Where accessible, visual inspections may be performed on two-phase flow lines.
- [2] Follow-up UT inspection is required for locations showing evidence of extensive wear.
- [3] Due to the qualitative nature of visual inspections, appropriate conservatism should be used when determining whether a component is acceptable to return to service and when establishing a re-inspection frequency.

## 5.9 DISPOSITION OF INSPECTION RESULTS

- [1] The following are used to disposition component inspection results. Reference attachment 9.3 for logic diagram

### NOTE

Certain components may have very little margin remaining as a consequence of high stresses in the line even though  $T_{pred} \geq 0.875 T_{nom}$  and therefore may require evaluation, for example Feedwater, Condensate, RHR, etc.

- [2] If  $T_{pred} \geq 0.875 T_{nom}$  the component is acceptable as is and may be returned to service.
- [3] If  $T_{pred} \leq 0.875 T_{nom}$  Evaluate for sample expansion (Reference section 5.12).
- [4] If  $T_{pred} \leq 0.3 T_{nom}$  for safety related piping repair or replacement is required.
- [5] If  $T_{pred} < 0.2 T_{nom}$ , for non-safety related, repair, replace or evaluate as warranted.
- [6] If  $T_{pred} \geq T_{acct}$  the component is acceptable for continued operations, however monitoring is required.



- [7] If  $T_{pred} < T_{accpt}$  a structural evaluation per ENN-CS-S-008 is required, also a sample expansion evaluation is required or repair or replace in accordance with the requirements of ASME Section XI Repair and Replacement Program.
- [8] If  $T_{meas} < T_{accpt}$  a structural evaluation per ENN-CS-S-008 is required.

#### 5.10 RE-INSPECTION REQUIREMENT

- [1] If the remaining service life of a component is greater than or equal to the number of hours in the next operating cycle, then the component may be returned to service.
- [2] If the component's remaining life is greater than the number of hours in the next operating cycle but is less than the number of hours in the next two operating cycles, then the component should be considered for re-inspection, repair or replacement during the next scheduled outage.
- [3] If the component is acceptable for continued service, then it shall be re-examined before or during the outage immediately prior to the cycle during which it is projected to wear to the minimum allowable wall thickness.

#### 5.11 COMPONENTS FAILING TO MEET INITIAL SCREENING CRITERIA

- [1] If the results of the remaining life evaluation are shorter than the amount of time until the next scheduled inspection, there are several options for disposition of the component, as follows:
- (a) Shorten the inspection interval (for components that can be inspected online)
  - (b) Refine the  $T_{accpt}$  value through a detailed stress analysis, which should be provided by Design Engineering.
  - (c) Repair or replace the component
  - (d) Safety class components that are less than or equal to  $0.3T_{nom}$  must be replaced or further structural evaluation is required.
- [2] Wall thinning resulting in less than  $T_{accpt}$  shall be reported immediately to the FAC engineer by verbal or written communications.
- [3] A condition report shall be generated when significant wall thinning or unexpected wear is detected in a system or component.
- [4] A condition report shall be generated for wall thinning below  $T_{accpt}$  or other site established limit and a subsequent structural evaluation performed to disposition the line for continued service.



- [5] If a previous condition report was generated for a component with wall thinning then no new condition report is required provided that the associated structural evaluation is current and applicable.

#### 5.12 SAMPLE EXPANSION

- [1] If a component is discovered that has a current or projected wall thickness less than the minimum acceptable wall thickness (T<sub>accpt</sub>), then additional inspections of identical or similar piping components in a parallel or alternate train shall be performed to bound the extent of thinning except as provided below. Reference section 5.12.2
- [2] When inspections of components detects significant wall thinning and it is determined that sample expansion is required, the sample size for that line should be increased to include the following:
- (a) Components within two diameters downstream of the component displaying significant wear or within two diameters upstream if the component is an expander or expanding elbow.
  - (b) A minimum of the next two most susceptible components from the relative wear ranking in the same train as the piping component displaying significant wall thinning.
  - (c) Corresponding components in each other train of a multi-train line with a configuration similar to that of the piping component displaying significant wall thinning.
- [3] If the expanded inspection scope detects additional degradation, the sample expansion should continue until no additional components with significant wear are detected.
- [4] Sample expansion is not required if the thinning was expected or if the thinning is unique to that component (e.g., degradation downstream of a leaking valve).
- [5] Inspections of components from the current or past outages may satisfy the sample expansion criteria, therefore, some of the sample expansion requirements can be met without performing additional inspections.
- [6] Sample expansion is not required for components that are being re-inspected if normal or expected wear is detected or wear unique to that component. All other wear patterns encountered shall be evaluated by the FAC Engineer to determine if sample expansion is required.



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### 5.13 REPAIR / REPLACEMENT OF DEGRADED COMPONENTS

- [1] The FAC engineer shall generate applicable documents to facilitate repair or replacement of degraded or deficient components.
- [2] Components experiencing severe or unacceptable wear should be replaced with corrosion resistant material. However like in kind may be appropriate if procurement of a resistant material would delay plant restart.
- [3] Replacing fitting-by-fitting that have experienced significant wear is a satisfactory approach to reducing wear if the wear is very localized (i.e., wear is concentrated downstream of a flow control valve or orifice).
- [4] Repairs and replacements to piping and components within the scope of Class 1, 2, 3 shall be performed in accordance with the requirements of ASME Section XI Repair and Replacement Program.
- [5] All temporary non-code repairs to ISI Class 1, 2, 3 shall comply with NRC Generic Letter 90-05.

### 5.14 COMPONENT EVALUATION PACKAGES

- [1] The FAC Engineer or designee shall assemble a component evaluation package for each examined component which may contain some of, but is not limited to the following:
  - (a) UT DATA Sheet
  - (b) Isometric drawing(s), sketches, flow diagram and digital photo.
  - (c) Reference to Structural /Minimum wall evaluation
  - (d) Component evaluation data sheet.

### 5.15 POST- INSPECTION ACTIVITIES

- [1] The FAC Program Engineer shall prepare an Outage Summary report to document the outage FAC activities and submit to Records for retention in accordance with applicable procedures.
- [2] Update CHECWORKS models with inspection data.
- [3] Update small bore susceptible report as applicable
- [4] Update all applicable FAC reports.



- [5] Update FAC System Susceptible Report as required.

#### 5.16 LONG TERM STRATEGY

- [1] The ENNE long-term strategy for increased safety, reduced costs and reduced FAC rates is accomplished through optimization of the inspection planning process, the use of improved materials for replaced components, improved water chemistry, and appropriate design changes.

#### 5.17 METHODS OF DETERMINING PLANT PERFORMANCE

- [1] Program performance indicators, self-assessments and bench marking are utilized as methods for monitoring program and plant performance.

### 6.0 INTERFACES

- [1] ENN-CS-S-008, "Pipe Wall Thinning Structural Evaluation".
- [2] ENN-EP-S-005 "Flow Accelerated Corrosion Component Scanning and Gridding Standard".

### 7.0 RECORDS

- [1] Record retention shall be in accordance with site procedures.

### 8.0 OBLIGATION AND REGULATORY COMMITMENT CROSS-REFERENCES

- [1] OBLIGATIONS AND COMMITMENTS IMPLEMENTED OVERALL

Document	Document Section	NMM Procedure Section	Site Applicability
QAPM	A6a, A6b, A6c, A6e	All	All
QAPM	B12a, b, c, d, e, f	All	All
QAPM	B15 a, c	All	All
8.0[1](a)	All		JAF
8.0[1](b)	All	All	JAF
8.0[1](c)	All		IPEC Unit 3
8.0[1](d)	All	All	IPEC Unit 3
8.0[1](e)	All	5.12	All
8.0[1](f)	All		IPEC Unit 2
8.0[1](g)	All	All	Pilgrim
8.0[1](h)	All	All	Vermont Yankee
8.0[1](i)(j)	All		Vermont Yankee



- (a) JAFP 87-0737, JAFNPP Docket No. 50-333, Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants.
- (b) JPN-89-051, JAFNPP Docket No. 50-333, Response to NRC Generic Letter 89-08 Erosion/ Corrosion Induced Pipe Wall Thinning.
- (c) IP3-87-055Z, Docket No. 50-286, Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants.
- (d) IPN-89-044, Docket No. 50-286, Response to NRC Generic Letter 89-08 Erosion/ Corrosion Induced Pipe Wall Thinning.
- (e) NRC Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repairs of ASME (ISI) Code Class 1, 2, 3 Piping".
- (f) Mr. Murray Selman (Con Edison) to Mr. William Russell (NRC) "Response to NRC Bulletin No. 87-01, Letter dated September 11, 1987.
- (g) BECo 89-107, Docket 50-293, Response to NRC Generic Letter 89-08 Erosion/ Corrosion Induced Pipe Wall Thinning.
- (h) Vermont Yankee letter to USNRC, FVY-89-66, Docket No. 50-271, Vermont Yankee Response to NRC Generic Letter 89-08, "Erosion/ Corrosion Induced Pipe Wall Thinning", Dated July 14, 1989.
- (i) Vermont Yankee letter to USNRC, FVY-87-94, Docket No. 50-271, Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants. Dated September 11, 1987.
- (j) Vermont Yankee letter to USNRC, FVY-87-121, Docket No. 50-271, Supplement to Vermont Yankee Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants. Dated December 24, 1987.

## 9.0 ATTACHMENTS

Guidance on Parameters affecting FAC.

Flow Accelerated Corrosion Program Attributes.

Wall Thinning Evaluation Process Map.



### GUIDANCE ON PARAMETERS AFFECTING FAC

Listed below are factors to be considered when reviewing work requests, component replacements and modification packages for possible impact on the content of the FAC Program governed by DC-315. All Design Change Packages (DCP's) are required to be evaluated for impact to the FAC Program. This list is not intended to be all-inclusive or to limit the number of items an individual would consider when performing this impact assessment. It is intended as a reasonable list of items to consider for potential program content updates.

1. Water Chemistry. Many water chemistry parameters have been shown to contribute to FAC.
  - a. pH Control Amine - pH is the primary chemistry parameter affecting FAC rates in PWRs. However, the amine used to control pH also plays an important role. Amines such as ammonia tend to separate more into the steam phase in two-phase flow conditions, and therefore provide less protection in the drains. Amines such as morpholine and especially ethanolamine have better partitioning characteristics for FAC.
  - b. In a BWR, pH has much less of a role since the pH is stable and there are no amine's added to control the pH. FAC rates decrease as pH level increases. FAC rates seem to drop considerably at pH values of greater than 9.3 - 9.5.
  - c. Oxygen Content - FAC rates decrease as oxygen concentration increases. Values that typically result in minimum FAC rates are approximately 15 to 20 ppb.
  - d. Hydrogen Water Chemistry - BWR Plants that do not have hydrogen addition normally have a main steam oxygen content near 18 ppm. Plants with hydrogen water chemistry typically have an oxygen content from 3 to 12 ppm. This has a potential to impact the corrosion rates in the LP steam systems; mainly the first and second stage reheater drains based on industry experience.
  - e. Hydrazine Injection - Hydrazine is added to the feed train of PWRs as an oxygen scavenger and to maintain a reducing environment in the steam generators. From zero to approximately 150 ppb, an increase in hydrazine concentrations seems to increase rates of FAC. Higher concentrations seem to result in no further increase in FAC rates. EPRI recommends the use of high levels of hydrazine (>100 ppb) to protect steam generator tubes; however, this can result in accelerated rates of FAC in the feed train. Although CHECWORKS does not currently model high hydrazine conditions, any model updates performed after the release of version 1.0F should carefully consider hydrazine concentrations.





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Flow Accelerated Corrosion Program

ATTACHMENT 9.1

GUIDANCE ON PARAMETERS AFFECTING FAC

Sheet 2 of 3

- f. Zinc Injection - Industry experience has shown that zinc injection decreases corrosion and FAC wear rates due to the concentration of zinc at the oxide surface. The amount of reduction depends on the amount of zinc at the surface.
2. Piping Geometry - Piping geometry is one of the most important factors in FAC. Generally, geometries that produce the greatest turbulence also produce the highest FAC rates. Listed below are examples of obvious items that should be considered in any assessment:
  - a. Addition or replacement of fittings, bends and branch connections.
  - b. Like for like replacement of any fitting in a system that is susceptible to FAC damage or is part of system that is already part of the FAC Program.
  - c. Alterations or repairs encountered in the nozzles or walls of FW heaters, MSR, Drain Tanks, FW Pumps, HD Pumps or CD/CB Pumps.
  - d. Throttled Valves.
3. Piping Material Composition - Alloying elements improve the resistance of piping systems to FAC. In ascending order of resistance, the following table presents the degree of improvement over carbon steel:

Material	Nominal Composition	Rate (carbon steel) / Rate (alloy)
P11	1.25% Cr, 0.50% Mo	34
P22	2.25% Cr, 1.00% Mo	65
304	18% Cr	>250
4. In-Line Components - Addition or replacement of such components as thermowells, flow elements and pressure-reducing orifices should be evaluated. The local effects caused by these components can generate FAC damage in areas where overall conditions don't indicate the need for inspections.
5. Component Supports - Additions or deletions of components supports which could result in the need for a review of the existing code minimum wall value or a new code minimum wall calculation.
6. Operational Changes - System operational changes such as the normal operation of emergency heater drains, switching of spare components, extended use of normal start-up or by-pass lines, etc.



ATTACHMENT 9.1

GUIDANCE ON PARAMETERS AFFECTING FAC

Sheet 3 of 3

7. Component Replacements – Records should be updated for like for like replacement of fittings already in the program including new baseline data, changing next scheduled inspection due date, etc. Note and track whether the replacement components have had surface preparation and a UT grid applied for future outage planning.
8. External Sources – Information concerning FAC Inspection results from other stations and Nuclear Plants operated by others. General information distributed by EPRI Reports, INPO & NRC Bulletins, etc. should also be considered.
9. Maintenance History – A review of the maintenance performed on valves, orifices, steam traps, etc. should be considered. Valves that have had seal leakage can cause very localized wear in systems normally exempted. Plugged traps create water pockets in steam systems that accelerate metal loss. Eroded orifices can cause increased metal loss due to decrease in back pressure and increase in flow rates.



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Flow Accelerated Corrosion Program

ATTACHMENT 9.2

FLOW ACCELERATED CORROSION PROGRAM ATTRIBUTES

Sheet 1 of 1

### PROGRAM ATTRIBUTES

#### Attributes:

##### Program Infrastructure

- (a) Program Structure: Roles & Responsibilities, Program Ownership, Organizational Interfaces, etc.
- (b) Flow Accelerated Corrosion Program Document.
- (c) Flow Accelerated Corrosion System Susceptibility Review, Latest Revision.
- (d) Report(s) Summarizing the Augmented portion of the FAC Inspection program, Latest Revision.
- (e) CHECWORKS models

##### Program Staffing and Experience

- (a) Background and Expertise.
- (b) Qualification and training.
- (c) Bench Strength.
- (d) Industry Participation.

##### Program Implementation

- (a) Inspections
- (b) Maintenance and Repairs
- (c) Control of Changes and Deferrals
- (d) Review of INPO Operating Experience documents, CHUG operating experience, NRC notices.

##### Health Monitoring:

- (f) System Engineering Health reports.
- (g) FAC Quarterly Health Reports.

##### Effective Assessment:

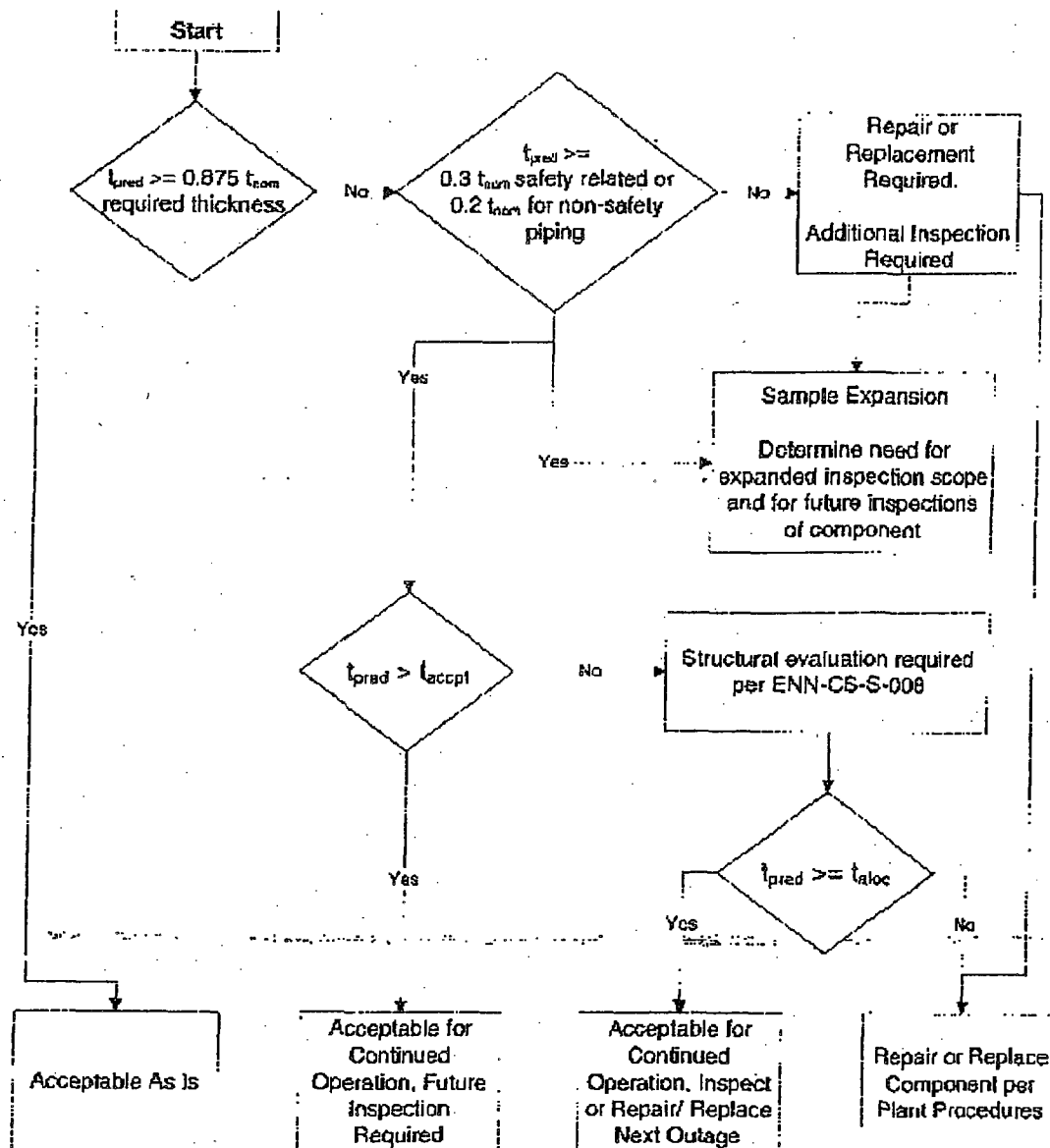
- (h) Perform FAC Self-Assessment on a periodic basis or as defined by applicable procedures.

##### Oversight:

- (k) Effective assessment, Benchmarking or Audits.



Logic Diagram - Evaluation of Pipe Wall Thinning



*Chockie Group International, Inc.*

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# **Aging Management and Life Extension in the US Nuclear Power Industry**

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October 2006

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Alan Chockie

Prepared for

The Petroleum Safety Authority Norway  
Stavanger, Norway

PSA Project Reference Number: NO 99B16

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## Executive Summary

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All systems and equipment degrade over time. However, the nature and the rate of degradation depend on such factors as the design, material, construction, mode of operation, and operating environment. With effective inspection and maintenance practices aging degradation can be managed and operational life can be extended well beyond what was originally planned. For over 25 years the United States (US) nuclear power industry and the US Nuclear Regulatory Commission (USNRC) have worked together to develop aging management programs that ensure the plants can be operated safely well beyond their original design life.

This report was prepared by the Chockie Group International to provide an overview of the aging management and life extension programs and regulations within the US commercial nuclear power industry and their possible applicability to the petroleum industry in Norway. It was prepared as part of the project for the Petroleum Safety Authority (PSA) Norway entitled, *Design Life Extension Regulations* (PSA Project Reference Number: NO 99B16).

Associated with this report are two companion briefing reports that provide focused examinations of two important aspects of life extension requirements. These are *Performance Monitoring of Systems and Active Components* (CGI Report 06.21) – an examination of the Maintenance Rule requirements for effective maintenance programs, and *Condition Monitoring of Passive Structures and Components* (CGI Report 06.22) – a review of the License Renewal Rule requirements and process for aging management of passive and long-lived structures and components.

There are three important principles associated with aging management. These are:

- maintaining the structures, systems, and components (SSCs) in "as new" condition – with no reduction in performance or safety margins
- preventing failures of critical SSCs
- understanding and managing the age-related degradation mechanisms

During the operating life of a plant these aging management principles should be an integral part of the maintenance program. However, when contemplating life extension another set of issues must be considered. As the US nuclear industry and the USNRC concluded, in order to extend the operating life beyond the original design life additional economic and technical factors need to be considered.

Although the possibility of life extension for nuclear plants in the US has existed for more than 50 years, the industry and regulator have been actively developing life extension requirements for only the last 25 years. In 1954 the original licensing requirements for US nuclear power plants set a 40-year limit for operating licenses. This 40-year limit was selected based on economic considerations rather than technical limitations. However, even at that time, the Atomic Energy Act was set up to allow renewal of the operating licenses.

In the late 1970s the USNRC and the nuclear industry began to address the issues concerning life extension. The first initiatives were directed at determining whether or not the safe operation of the plant beyond its 40-year operating limit could be technically justified. That is, could the aging effects be adequately managed so the plant could be operated within the original safety margins during the period of extended operation?

To answer this question both the USNRC and the industry initiated a number of aging research programs. One of the largest aging research efforts was the Nuclear Plant Aging Research (NPAR) Program. This 10-year, multi-million dollar effort was sponsored by the USNRC and produced over 150 aging research reports. Other aging research programs by the industry complimented the work of the NPAR program. Based on the results of these programs it was concluded that many aging phenomena are readily manageable and do not pose technical issues that would preclude life extension for nuclear power plants. As long as there are effective inspection and maintenance practices the plant life is simply limited by the economic cost of repair or replacement of any components that do not meet specified acceptance criteria.

The USNRC then moved forward with the development of license renewal requirements and published the initial License Renewal Rule in 1991.

For over fifteen years the USNRC and the nuclear industry have been continuously refining both the license renewal requirements and the renewal process. There are many aspects of these efforts and lessons learned that can be of potential value to the PSA and the Norwegian petroleum industry.

The following are some of the key lessons from the development and implementation of aging management programs and life extension requirements that could be applicable to the PSA and the Norwegian petroleum industry in their consideration of life extension and aging management.

#### **Aging Research Information**

The wealth of aging related information produced by the NPAR and industry aging research programs remains a useful resource for both nuclear and non-nuclear organizations. Although the aging studies examined SSCs with respect to their operation in the nuclear plants, much of the aging degradation and aging management information is applicable to the petroleum and other industrial sectors.

#### **Continuous Improvement**

Over the years both the USNRC and the industry have been working to make the license renewal requirements and the renewal process more efficient and effective. For example, the initial version of the License Renewal Rule did not provide a predictable nor stable process – it was too open ended and too broad a scope. It was determined that many aging effects were already adequately addressed during the initial operating license period. Also, the initial Rule did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which help manage plant aging phenomena as part of the on-going maintenance program tasks.

The resulting revised Rule established a simpler, more stable, and more predictable regulatory process. The key changes that were made included:

- focusing on the adverse effects of aging rather than identification of all aging mechanisms such that identification of individual aging mechanisms is not required
- simplifying the integrated plant assessment process and making it consistent with the revised focus on the detrimental effects of aging
- adding an evaluation of time-limited aging analyses (TLAA)
- requiring only passive, long-lived structures and components to be subject to an aging management review for license renewal, thus removing active SSCs from license renewal

### **Passive Versus Active**

An important aspect of the US nuclear plant life extension requirements is the distinction between passive and active systems, structures, and components. Passive SSCs are those that do not move to function (such as structures, heat exchangers, cables, valve and pump bodies, and piping). Their age related degradation can only be monitored and trended by performing periodic condition assessments (such as inspections, testing, and measurements).

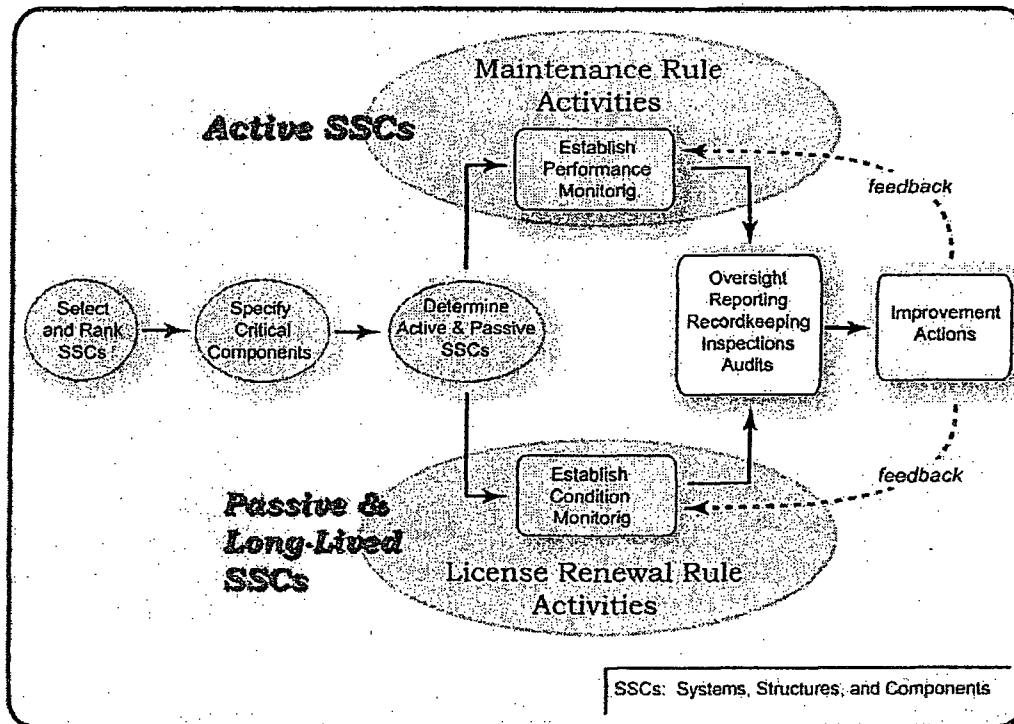
By focusing the license renewal process on safety critical passive and long-lived components the process has been reduced to manageable proportions – licensees are not required to consider all SSCs in order to justify extended operations.

A diagram of the relationship of the License Renewal and Maintenance Rules to the aging management of active and passive SSCs is shown in the figure on the next page.

During the renewal process, the licensee must confirm whether the original design assumptions will continue to be valid throughout the period of extended operation or whether aging effects will be adequately managed. The licensee must demonstrate that the effects of aging will be managed in such a way that the intended functions of passive or long-lived structures and components will be maintained during extended operation.

### **Need for Guidance**

One of the key lessons has been the need to provide clear guidance and support to all involved parties. Both the USNRC and the industry have developed guidance documents to assist in the development of aging management programs, the preparation of the renewal application, and the review of the application. As lessons are learned these guidance documents are revised to capture new insights or address emerging issues. Along with the guidance documents, training programs and support activities have greatly reduced the time and expense in preparing, reviewing, and approving the license renewal applications.



### Other Aging Management Lessons Learned

In reviewing the aging management and life extension efforts of the nuclear industry there are several areas where the experiences of the US nuclear power plants and USNRC could be of value to the PSA and the petroleum industry. These include:

- integrating aging management and maintenance requirements – careful management to avoid duplication of effort and non-effective maintenance tasks
- developing a long-term maintenance strategy – linking asset management to maintenance strategy with the objective to preserve the assets as long as economically feasible
- reducing component failures – being proactive to identify incipient failures, precursors, and age related degradation.
- effectiveness of condition monitoring – improving the application of diagnostic analysis to prevent failures
- establishing appropriate inspection procedures
- aging management of inaccessible equipment (since replacement and repair is not usually an economically feasible option)
- sharing experiences by tracking generic failures and monitoring effectiveness of aging management activities
- implementing pilot projects to evaluate the effectiveness of new requirements and processes

- properly quantify consequential failure costs – to support reliable conclusions and to justify implementation of a predictive maintenance and effective aging management strategy

### **Conclusions**

The aging management and life extension process for the US nuclear industry has been refined and improved over the years. It has become an efficient and effective method to ensure that the nuclear plants in the United States can be safely operated beyond their original 40-year operating license. By dividing the safety critical systems, structures, and components into passive and active categories the industry and regulator have reduced the potentially overwhelming analysis effort to a reasonable and manageable size.

By working together, the nuclear industry and the US Nuclear Regulatory Commission (USNRC) have been able to technically justify life extension. The process has been structured to not be an economic or resource burden on either the licensees or the USNRC. However, all parties are continually reviewing the process and results to identify where improvements can be made.

The process has been selected as a viable method by many international regulatory and nuclear industry organizations, including those in Spain, Taiwan, and Korea. The International Atomic Energy Agency in Vienna has also adopted the process as the model for ensuring safe extended life operations.

The aging management and life extension process can be easily adapted to other industries. The development strategy, research material, specific elements of the process, and many of the lessons learned can all be of potential value to the PSA and Norwegian petroleum industry in ensuring safe extended operations of the facilities.

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# **Aging Management and Life Extension in the US Nuclear Power Industry**

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## **Background**

This report on aging management and life extension actions within the United States (US) nuclear power industry was prepared by the Chockie Group International as part of the project for the Petroleum Safety Authority (PSA) Norway entitled, *Design Life Extension Regulations* (PSA Project Reference Number: NO 99B16).

### ***Report Objective***

The objective of the report is to provide an overview of the development and application of aging management and life extension programs and regulations within the US commercial nuclear power industry.

This report is a companion to two previous briefing reports that the Chockie Group International prepared for the PSA. The first, entitled, *Performance Monitoring of Systems and Active Components* (CGI Report 06.21), examined the requirements and activities associated with aging management of active systems and components. The second briefing report, *Condition Monitoring of Passive Systems, Structures, and Components* (CGI Report 06.22), addressed the programs and regulations for aging management of passive systems, structures and components for extended operation.

Information from these two briefing reports has been incorporated into this overview report.

### ***The Principles of Effective Aging Management***

It is a well-established fact that mechanical and electrical equipment can be maintained over long periods of time, using refurbishment, partial/complete replacement and reconditioning. There are some automobiles from the early 1900's that now look better and work better than when they were made. The technology to maintain equipment in an "as new" condition is called effective aging management. There are three basic principles that form the foundation of aging management programs.

The first principal is that there can be not reduction in the safety margins over the useful life of the plant. With respect to commercial nuclear power plants, the Nuclear Regulatory Commission (USNRC) does not permit reduction in safety margins. This implies that the plant licensees must maintain the plants in as new condition.

The second major principal is to avoid failures. The reliability of the plant will never be better than its worst performing system or component. To avoid failures, one must have the skills, knowledge, and experience to recognize pending failures and take timely

corrective actions for all structures, systems, and components that are critical to the safe operation of the plant.

The third principal is to understand the behavior of materials when exposed to certain stressors (in other words, to understand the applicable aging mechanisms). This knowledge helps focus attention on the "right places and at the right time". This also provides the information necessary for addressing the aging degradation situation with the right tools and developing effective actions to mitigate or prevent the problem from affecting safe plant operations.

Since the beginning of nuclear power in the US the industry and regulator have embraced these principles and have worked to ensure that the plants are properly maintained and operated over their operating life.

### ***The Push for Life Extension***

The operating life of the US plants has been limited to 40-years as is discussed in more detail in the following section. However, almost twenty-five years ago both the industry and the USNRC began to address the possibility of life extension. The first question they need to answer was whether it was technically justifiable and economically feasible to operate the plant beyond the original 40-year limit? If so, then what should the life extension approval process? The results of hundreds of aging research studies and many years of work have convinced all parties that life extension is both economically and technically viable. To ensure that the plants continue to operate within their design safety margins during extended operation, the USNRC in coordination with the nuclear industry had developed an effective and efficient license renewal process. The License Renewal Rule is discussed in detail in the CGI Report 06:22 and is summarized in later sections of this report.

### ***Report Content***

The first section of the report provides a brief historical perspective of the rationale for the life extension requirements and how the process has been split along the lines of active and passive systems, structures, and components.

The second section examines the key organizations that have been instrumental in the development of aging management programs. Included is an overview of how the various programs relate and complement each other.

The third section provides a discussion of the principal aging management and life extension program. The following sections examine the two key aging management requirements, the USNRC License Renewal Rule and Maintenance Rule.

The importance of industry developed aging management programs and the support and sponsorship of aging research by both the USNRC and industry is reviewed next. In the following sections a number of relevant issues and activities including early license renewal and international applications are examined.



The last part of the report discusses the lessons that have been learned over the twenty plus years in developing and implementing the aging management and life extension programs and requirements. Also as part of this later section is a summary of information, tools, strategies, and lessons that may be applicable to the PSA and Norwegian petroleum industry – how the PSA and the industry can take advantage of the extensive work and lessons to develop “focused” life extension requirements to ensure that adequate levels of safety are maintained during extended operation.

## Historical Perspective

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### *The 40-Year Operating License*

When the original licensing requirements for United States commercial nuclear power plants were developed it was agreed to limit the licenses for a 40-year operating period. The 40-year limit was selected based on economic considerations rather than technical limitations.

The 40-year limit was specified by the US Congress in the Atomic Energy Act of 1954. The law was modeled on the Communications Act of 1934. This Act set up the conditions for radio stations to be licensed and operate for several years. Then the stations would be allowed to renew their licenses as long as they continued to meet their charters. Similarly, the Atomic Energy Act allows for the renewal of operating licenses for the nuclear power plants.

Congress selected 40 years for nuclear power plant licenses based on the view that this was the time required to pay off the plant investments through the anticipated income from the electrical rate base. The 40-year license term was not based on safety, technical, or environmental factors.

As specified in the Atomic Energy Act, the plants can reapply for a new operating license after 20-years of operation. If granted, the new license covers the remaining term of the 40-year operation plus up to a 20-year extension. The regulations do not set any limit on the number of renewals that a plant can apply for.

Renewal is voluntary. The decision is primarily economical and whether the licensee believes they can continue to meet NRC requirements. By June 2006, 21 nuclear plants have received regulatory approval for 20-years of extended operation. Another nine plant applications are being reviewed.

### *The Importance of Passive versus Active*

The US Nuclear Regulatory Commission (USNRC) and the nuclear industry have developed a strategy to ensure the extended safe operation of the plants. An important element of the US strategy is the distinction between passive and active systems, structures, and components (SSCs). As a general definition, passive SSCs are those that do not move to function (such as, structures, heat exchangers, transformers, valve and pump bodies, and piping). Their age related degradation can only be monitored and trended by performing periodic condition assessments (such as inspections, testing, and measurements). An aging evaluation is typically required to identify the degradation mechanisms and to select the effective inspections and tests.

In order to ensure that the US nuclear power plants continue to maintain adequate levels of safety during extended operation beyond their original license period the USNRC has developed two important sets of requirements. These are the:

- Maintenance Rule
- License Renewal Rule

The requirements for the aging management of "active" systems and components are addressed by the Maintenance Rule (as discussed in CGI Report 06.21). The aging management of active SSCs should be part of the plant maintenance program. Good maintenance practices should identify and correct any aging degradation issues of the active SSCs and that no special license renewal aging management requirements are necessary for extended operational approval.

The focus of the License Renewal Rule is on the management of aging degradation of safety critical "passive" and long-lived systems, structures, and components (SSCs) at the nuclear power plants (as discussed in CGI Report 06.22). Long-lived items are those that are not subject to replacement based on a qualified life or specified time period.

Copies of the Maintenance Rule and the License Renewal Rule are provided in Appendices A and B, respectively.

### ***Benefits of Life Extension***

The industry and government have assessed the potential economic and environmental impact of life extension. Extending the useful plant life by 20 years for the 104 operating US plants is the equivalent of building 52 new plants. It would be most likely that these 52 replacement power plants would be coal fired. The avoidance of harmful plant emissions (SO<sub>x</sub>, NO<sub>x</sub>, heavy metals, and ash) is a significant environmental accomplishment (see Figure 1). Additionally, life extension is a way of minimizing the current bottleneck for the disposal of used spent fuel. Over the years, there have been numerous delays in the development of a final national repository for spent nuclear fuel. The extension of the operating licenses will allow the plants to continue to store the material on-site until the repository becomes available.

On the economic scale, each plant represents an asset value of between \$1 billion to \$2 billion.

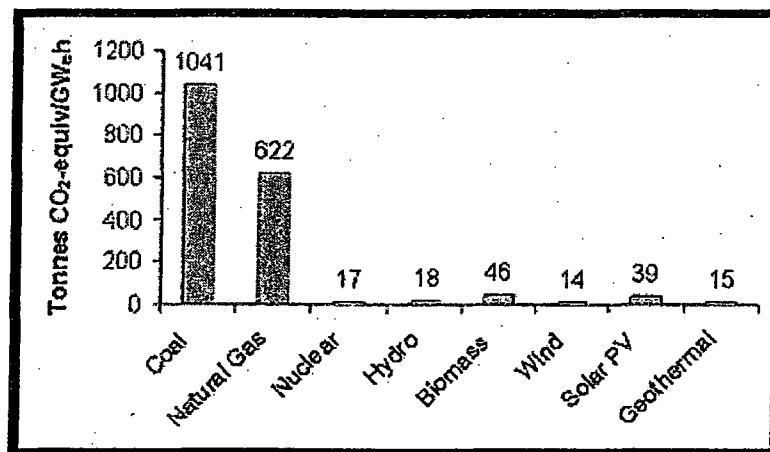


Figure 1: Comparison of Life-Cycle Emissions

The largest part of the operating costs comes from the depreciation of the original investment over the first 40 years and the decommissioning fees. After 40 years, the only remaining capital costs are those associated with refurbishment and replacement of aging components. The fuel and operations and maintenance costs are much lower than comparable size coal or oil fired plants. The overall benefit-to-cost ratios are on the order of 2:1 to 4:1 (a saving of between \$500 and \$1000 million) over the period of extended operation. According to the Nuclear Energy Institute:

*... the economic value of the U.S. nuclear fleet over the remaining 40-year life of the plants is approximately \$65 billion, and, over a 60-year life, assuming license renewal, is \$76 billion. (Economic value is net present value of future revenue stream net of fuel and O&M costs, capital additions, etc., expressed in 2002 dollars.)*

Life extension also brought into focus the value of increasing capacity factors and the possibility of power uprate. Many plants have already completed significant power uprates, gaining 10% to 15% additional capacity with little investment. In fact, the equipment reconditioning and replacements performed as a result of life extension are made to also satisfy the needs of power uprate that is new equipment is purchased with additional capacity or upgraded. Capacity factors for the operating plants have been increasing over the last ten years, mostly by reducing the number of outage days for refueling and avoiding plant shutdowns. The average fleet capacity factor has increased about 10% to the present value of around 90%. The combined effect of power uprate and capacity factor increase has provided the equivalent electric output of about 26 additional nuclear plants. These efforts were made possible by the prospect of life extension and the attendant economic savings.

Because most of the cost of electric production from nuclear plants in the US is regulated at the state level, the net savings by the plant operators are ultimately passed on to the consumer. As a result, the economic benefits from more efficient extended operation should be realized by the utility customers.

## **Development of Aging Management Programs**

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This section examines the key organizations that have been involved in the development and improvement of programs to identify and manage the effects of aging on plant systems, structures, and components (SSCs). Also briefly discussed is the relationship among the many industry and regulatory aging management related programs.

### ***Key Organizations Involved in Nuclear Plant Aging Management***

There have been a number of industry and governmental organizations involved for over twenty-five years in the development of aging management programs and requirements for the extended operation of US nuclear plants. The key organizations are:

- Industry Organizations
  - Electric Power Research Institute (EPRI)
  - Institute of Nuclear Power Operations (INPO)
  - Nuclear Energy Institute (NEI)
  - Boiling Water Reactor Owners Group
  - Westinghouse Owners Group
  - Babcock and Wilcox Owners Group
  - Combustion Engineering Owners Group
- Governmental Organizations
  - US Department of Energy (DOE)
  - US Nuclear Regulatory Commission (USNRC)

The principal aging related activities of these various organizations are summarized below.

### **EPRI Aging Research**

EPRI, the research arm of the electric utilities, sponsored life extension pilot plant and demonstration projects. These studies provided the initial technical and economic impetus for individual plant owners to look at plant life extension as a serious option for their long-term generation planning. EPRI aging research projects established the basic aging assessment technology and aging management principles. EPRI programs concerning mechanical, electrical, and structural equipment identified potential aging mechanisms and the effects of aging degradation (those that manifest themselves and can be visually or otherwise observed).

EPRI and various nuclear plant owners groups also sponsored the development of Industry Reports on Component Aging. Aging Management Tools for mechanical, electrical and structural equipment were produced to provide guidance to the plant licensees.

A similar effort was undertaken to deal with the aging management of the non-safety related portion of the plant. EPRI initiated the Preventive Maintenance Basis project to

develop an industry consensus of best practices for maintenance and aging management. This project was closely followed by the EPRI Life Cycle Management program to create long-term maintenance strategies on the basis of highest reliability at the lowest costs.

#### **INPO Maintenance Management Guidance**

Initially there were no uniform implementation procedures for the aging management programs related to non-safety structures, systems, and components (SSCs). INPO lead the development of an equipment reliability guide [AP-913] that incorporating the preventive maintenance (PV) basis, life cycle management (LCM) programs, and reliability centered maintenance (RCM) programs. AP-913 has become the standard to measure plant excellence.

#### **NEI Aging Guidelines**

The Nuclear Energy Institute has been responsible for taking the lead in the development of the guidelines to assist licensees prepare the license renewal applications. The NEI-95-10 document, entitled *Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule*, provides licensees with an acceptable approach for implementing the requirements of the USNRC License Renewal Rule. This is a living document and is continuously updated based on NEI's monitoring of licensees experiences with the license renewal process. NEI continues to be the focus for interaction between the industry and the USNRC and serves as a spokesperson for the industry when new life extension or aging management issues emerge.

#### **DOE Aging Research**

The US Department of Energy (DOE) is responsible for national long-term energy planning. DOE has supported a number of the EPRI programs including those addressing mechanical, electrical, and structural equipment aging degradation. Follow-on research by DOE has included the Aging Management Guides for major components and commodities and the concrete aging research conducted by the DOE Oak Ridge National Laboratory.

#### **USNRC License Renewal Research & Regulations**

In the early 1980s the USNRC initiated a major aging research program to investigate the aging degradation of safety related equipment. This program, entitled the Nuclear Plant Aging Research (NPAR) program, examined aging degradation in both passive and active structures, systems, and components. This was a major multi-million dollar research effort lasting almost 10 years and sponsoring more than 100 aging research studies. The Program eventually generated over 150 technical reports.

The findings from the NPAR Program provided the basis for determining that extended operations of the nuclear power plants were technically justifiable. It also provided the foundation for the license renewal requirements and renewal process.

In 1991, the safety requirements for license renewal (entitled, Requirements for Renewal of Operating Licenses for Nuclear Power Plants) were adopted by the USNRC. These requirements, known as the License Renewal Rule, established the procedures,

criteria, and standards governing the renewal of nuclear power plant operating licenses. These were made mandatory requirements as part of the United States Code of Federal Regulations (commonly referred to as 10 CFR Part 54).

For the next few years the USNRC in cooperation with the nuclear industry conducted a demonstration program to apply the Rule to pilot plants. The objective was to assess the effectiveness of the requirements and the application/review process. The USNRC also undertook a number of activities related to the implementation of the Rule. These included:

- developing a draft regulatory guide
- developing a draft standard review plan for license renewal
- reviewing generic industry technical aging information

Based on discussions with industry and results from the demonstration program the USNRC determined that revisions to the Rule were needed. The USNRC found that many aging effects are dealt with adequately during the initial license period. In addition, the USNRC found that the review did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which also helps manage plant aging phenomena.

In summary, the amended Rule established a regulatory process that is simpler, more stable, and more predictable than the initial License Renewal Rule. It put the focus of the license renewal assessment on the licensees aging management activities concerning passive and long-lived SSCs. It also clarified the focus on managing the adverse effects of aging rather than identification of all aging mechanisms. The changes to the integrated plant assessment (IPA) process were to make it simpler and more consistent with the revised focus on passive, long-lived structures and components

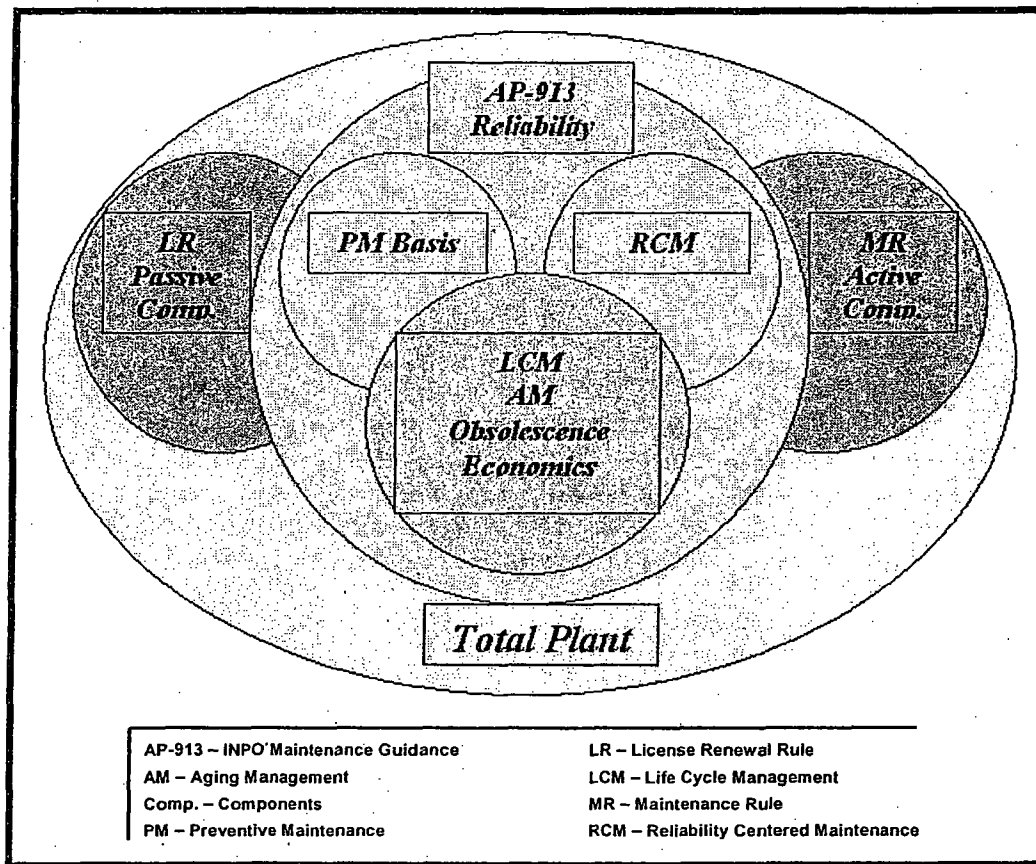
### ***Relationship of Aging Management Programs***

The original life extension pilot plant studies performed in the 1980's did not differentiate among passive and active components or the safety and non-safety related portions of the plant. The focus of these studies was to determine the critical components and life ending scenarios as a result of progressive unmitigated degradation and from this to establish a realistic attainable plant life. When the USNRC started to develop the License Renewal Rule, they had the benefit of the pilot studies results and included the passive and active components within the scope of the Rule. This turned out to be a bad decision, as industry tried to cope with very costly implementation costs and impractical application of the requirements. Because the Maintenance Rule was being prepared by the USNRC in the same timeframe and dealing exclusively with the performance monitoring of active components and systems, the License Renewal Rule was revised to only encompass long-lived passive components and structures. Notably, the USNRC regulations only apply to the regulated safety related portions of the plants, about one-third of the total plant. (A detailed review of the Maintenance Rule is provided in CGI Report 06:21.)

When life extension or license renewal is considered, the entire plant needs to be assessed and prepared to meet its extended life goal. To this end the industry sponsored

a number of equipment reliability research studies concerning the aging degradation for the non-safety portions of the plant. The initial focus was the development of Reliability Centered Maintenance (RCM) to identify critical component/parts. It was followed by the Preventive Maintenance Basis (PMB) to collect and document industry "best practices" for the maintenance of equipment. The relationship of the various industry and USNRC programs is shown in Figure 2.

However, the early aging studies and the license renewal efforts quickly pointed to a maintenance gap. Plants did not have, nor were they developing, and long-term aging management programs. As a result, EPRI sponsored the development of a Life Cycle



**Figure 2: The Relationship of Aging Management Programs**

Management (LCM) methodology for the plants to use to determine the most effective alternative from a number of scenarios. As defined by AP-913, life cycle management (LCM) is:

*... the process by which nuclear power plants integrate operations, maintenance, regulatory, environmental, and business activities that manage plant condition (by means of aging and obsolescence management), optimize operating life (including the options of early retirement and license renewal), and maximize plant value while maintaining plant safety.*



LCM can provide a basis for a long-term maintenance strategy with the highest reliability at the least cost. LCM makes use of RCM and PMB in addition to addressing technical obsolescence, aging management and the generic and plant-specific operating experience. The LCM program also considers economics to select the optimum long-term maintenance strategy.

INPO lead the development of the "umbrella" process that incorporates the various maintenance and aging management programs and requirements. This resulting industry guidance document, entitled, *Equipment Reliability Process Description* (AP-913), has become the industry standard by which plant maintenance performance is currently judged.

A related maintenance oversight activity is exercised by the insurance companies, such as Nuclear Equipment Insurance Limited. These insurance companies have created similar maintenance standards to be followed with the objective of minimizing their liability exposure. A benefit-penalty system has been applied by which the insurance premiums are determined based on the level of compliance with their maintenance standards.

## The Industry “Umbrella” Program (AP-913)

The *Equipment Reliability Process Description* (AP-913) developed by INPO has become the industry umbrella for effective plant maintenance practices. Many plants have adopted all or portions of AP-913, including the applicable parts of the regulatory programs, such as the aging management and performance monitoring parts of the License Renewal Rule and Maintenance Rule, respectively. It is important to note that the AP-913 is an industry initiative and is not a mandatory requirement. However, INPO’s role as an industry oversight organization for utility corporate and plant performance assures that most plants implement part or all of the recommended equipment reliability program guidance.

Large utilities with a substantial number of plants are creating their own organizational standards that essentially mirror the AP-913 program features.

The AP-913 process, as shown in Figure 3, consists of six basic elements. Each element, as briefly described below, has a series of considerations or tasks, which should be part of an effective maintenance program.

### Scoping and Identification of Critical Components

There are basically three categories of components within the plant. First, and most important, are the critical components that would shut down the plant or initiate safety

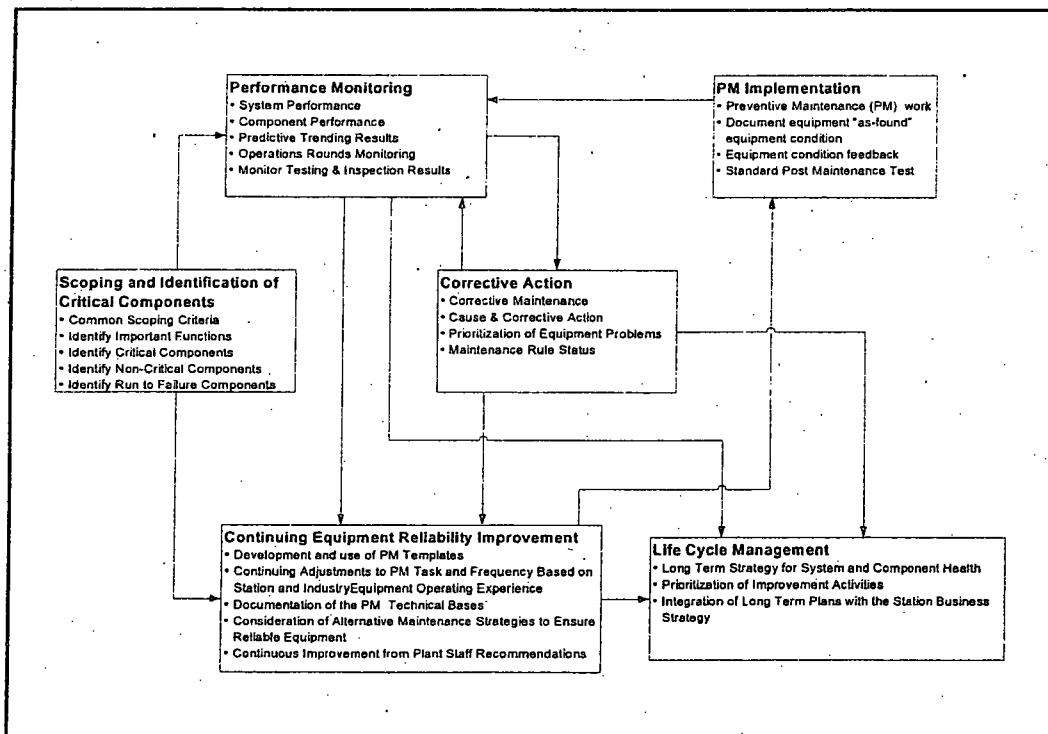


Figure 3: *Equipment Reliability Process* (Source: INPO AP-913)

systems if they were to fail their functions. The second category is the non-critical components that are being maintained by regular or vendor recommended maintenance. The third category is the run-to-failure components for which maintenance is not economically justifiable. These components are replaced on a set time schedule or following their failure.

### **Performance Monitoring**

For the critical and non-critical components, performance monitoring as required by the USNRC Maintenance Rule is applied at the system or component level (reliability and availability). Performance trending is conducted to assure that mitigative or corrective actions are contemplated prior to the component or system exceeding its performance limits.

The routine system of engineer and operator rounds is one example of recommended performance monitoring tasks. The rounds are undertaken frequently (such as daily or weekly) to detect minor changes in equipment behavior. Tasks to be administered during the rounds may include visual observation of the equipment looking for missing/loose parts, leakage, noise, fumes/smell, missing insulation, construction debris, abnormal vibration, discoloration and rusting, deformation, and cracking of foundations. Operators are required to confirm the correct position of breakers and switches, read local instrumentation, and verify position of fire and security barriers/doors.

At the crafts level, a "*condition code*" process has been implemented by most plants to facilitate condition feedback for the equipment being worked on. This condition code typically includes three to five levels of equipment conditions as observed by the maintenance personnel. Typical levels of condition codes may be:

- Condition 1: As New
- Condition 2: Meets or exceeds expectations
- Condition 3: Shows signs of acceptable wear/degradation
- Condition 4: Should be scheduled for overhaul, replacement
- Condition 5: Found in failed condition

These conditions are simple observations and are recorded on a standard form with the work package to be evaluated by the system engineer. A more detailed condition code table, using a 10-point graduation, is included in AP-913 presented in Table 1.

Other recommended considerations for performance monitoring include:

- use of equipment history and the corrective action database to perform equipment failure trending for components used across several systems
- specific alert values for condition-monitoring data in the component performance criteria

**Table 1: Equipment Condition Codes (Source: AP-913)**

<b>CONDITION 1</b>
Unanticipated Failure Failure not associated with normal wear or aging discovered at time of activity Condition Report required to address condition Potentially misapplied structure, system, or component requiring engineering resolution
<b>CONDITION 2</b>
Repair/Replacement Required, Not Necessarily Due to Normal Wear or Aging Failure not definitely attributable to normal wear or aging; can be repaired with replacement in kind material, parts, or components May require engineering resolution
<b>CONDITION 3</b>
Repair/Replacement Required, Due to Normal Wear or Aging Failure that is obviously due to normal wear or aging that can be repaired without engineering evaluation Consider performing the PM task more frequently
<b>CONDITION 4</b>
Measured Parameter Outside Specified Tolerance Component has not failed, but adjustment is required No replacement parts other than those dictated by the PM task required Consider performing the PM task more frequently
<b>CONDITION 5</b>
Reliability Degraded Component has not failed, but replacement or repairs recommended due to normal wear or aging to ensure reliable operation until the next inspection Consider performing the PM task more frequently
<b>CONDITION 6</b>
Measured Parameter Within Tolerance, but Adjustment Required Adjustments required due to normal wear, aging, or drift No replacement parts other than those dictated by the PM task required
<b>CONDITION 7</b>
Satisfactory Observed wear considered normal No adjustments required No replacement parts other than those dictated by the PM task required
<b>CONDITION 8</b>
Superior Observed wear less than would be expected No adjustments required No replacement parts other than those dictated by the PM task required Consider performing the PM task less frequently
<b>CONDITION 9</b>
Like New Component is in "like new" condition Consider performing the PM task less frequently
<b>CONDITION N</b>
As-Found Condition Not Applicable Administrative task One-time performance Condition monitoring task

- trending of as-found equipment condition codes to:
  - identify patterns of degradation by component type and the need to adjust preventive maintenance (PM) tasks or frequencies
  - update PM templates based on station equipment operating experience
  - to identify PM outliers for additional evaluation

- use industry event database (EPIX) to identify component trends being experienced by other plants, and take proactive measures to avoid similar failures
- identify aging or obsolescence issues
- evaluate the relationship between component performance and effect on system functional performance
- trend key data collected on operator rounds
- consult non-nuclear sources of component failure information and trending parameters/strategies

### **Corrective Actions**

This is perhaps the most important element, in that it directs the plant to perform a rigorous root cause evaluation of equipment failure. It also requires management actions to develop a plant culture of preventing future failures. According the AP-913:

*This is one of the hard links management can establish to reinforce an intolerance for unexpected equipment failures. By establishing management expectations that evaluations of unexpected failures include the question of why the failure occurred and what process should have prevented it, instead of just repairing it, continuous equipment reliability improvement initiatives become a way of life. This is also an opportunity to revisit a previous decision to run to failure.*

An evaluation is required to determine if the failure was preventable, using the following considerations:

- What existing barriers should have prevented the failure (procedure completeness, procedure implementation, craft training, post-maintenance testing, tag-out restoration, use of operating experience, troubleshooting, unavailability management, and human performance)?
- What barriers should be implemented to prevent recurrence? Consider the risk/benefit of the change.
- What other components are susceptible to this failure mechanism; what is the extent of this condition?
- How did the continuing equipment reliability improvement process miss this?
- Could more frequent implementation of existing preventive maintenance actions prevent recurrence?
- Should the scope of the preventive maintenance tasks be increased?
- Is there an aging or obsolescence concern that should be addressed in the corrective actions?
- Is additional corrective maintenance needed?
- Is the failed component in USNRC Maintenance Rule scope or did the failure cause a significant power reduction?
- Provide equipment root cause training and qualification, including the requirement to participate in a certain number of root cause analyses per year.

- Develop root cause specialists or mentors, with additional training and experience, in departments that frequently participate in this activity.
- Use a graduated approach for root cause determination commensurate with the level of consequences of the failure. Examples include trending only, apparent cause determination, root cause determination by an individual, and forming a root cause team.
- Establish clear methods to obtain vendor expertise or increased failure analysis for equipment failures whose root cause cannot be determined by a team.
- Search in-house and industry operating experience, including EPIX, to determine if similar failures have occurred.
- Are similar components affected by the same problem?

### **Continuing Equipment Reliability Improvement**

This element is the focus of the INPO equipment reliability strategy. It is structured to reflect a living maintenance program with continuous feedback, enhancements based on equipment performance, adjustments to PM frequencies to compensate for poor or excellent performance, to look for alternative solutions, recognize application of new technologies/diagnostics and to eliminate low value tasks and/or add new tasks where the need arises. Equipment reliability is tightly coupled to the need to identify incipient failures, monitor failures at other plants and look for precursors. This means that we know the locations, susceptibility to failure and the potential degradation, such that effective monitoring methods can be engaged. This element suggests that the following monitoring methods be considered:

- Degradation can be monitored by installed instrumentation.
- Degradation can be detected by a predictive maintenance technique such as vibration, oil sampling, thermography, or motor signature analysis.
- Degradation can be visibly observed during operator rounds or system engineer walkdowns.
- Degradation can be measured by surveillance testing.

### **Long-Term Planning and Life-Cycle Management**

With the event of power uprate (increasing the power output beyond the design levels, e.g., 115 to 120%) and life extension for the nuclear plants, it became evident that long-term plans needed to be developed to support cost-benefit assessments of these major capital projects and to formulate a lifetime maintenance strategy for the plants. The utilities were used to strategic planning with respect to power need forecasts, selecting the type of power generation and revenue projections, however, the nuclear plants needed a more sophisticated asset management tool, taking into account the unique life cycle and major capital expenditures for these plants. The Life Cycle Management (LCM) methodology and process was developed to fit this gap and was subsequently integrated with AP-913. This integration specifically recognizes the need to merge the long-term maintenance strategy with the station business plan.

### **Preventive Maintenance Implementation**

Lastly the program addresses implementation issues of the equipment reliability process. Plants are expected to have a rigorous work order system by which maintenance activities can be scheduled, implemented and recorded. The work order database provides a historic record of all work performed and includes data fields for the type of activity (preventive, corrective, design change, surveillance testing, operations test, etc) for each component, the date, required hours and in many cases also the labor and material costs. The data such constitutes a significant element for the reliability assessment in that the number of failures (each component and all similar components) can be sorted by year, cost and type, from which failure rates can be computed. Trending of the number of preventive and corrective work orders can be performed to ascertain whether the trend is stagnant, positive or negative. The effectiveness of the maintenance program can therefore be measured over time.

## The License Renewal Rule

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In 1954 the original licensing requirements for US nuclear power plants set a 40-year limit for operating licenses. This 40-year limit was selected based on economic considerations rather than technical limitations. However, even at that time, the Atomic Energy Act was set up to allow renewal of the operating licenses.

In the late 1970s the USNRC and the nuclear industry began to address the issues concerning life extension. The first initiatives were directed at determining whether or not the safe operation of the plant beyond its 40-year operating limit could be technically justified – could the aging effects be adequately managed so the plant could be operated within the original safety margins during the period of extended operation?

To answer this question both the USNRC and the industry initiated a number of aging research programs. One of the largest aging research efforts was the Nuclear Aging Plant Research (NPAR) Program. This 10-year, multi-million dollar effort provided the basis for determining that extended operations were technically justifiable. It also provided the foundation for the license renewal requirements and renewal process.

The NPAR Program identified aging as the cumulative, time-dependent degradation of a systems, structures, and components (SSCs) that, if unmitigated, could compromise continuing safe operation of the plant. Mitigating measures are therefore needed to ensure that aging does not reduce either the operational readiness of a plant's safety systems or the defense-in-depth through common-mode failures of redundant, safety-related equipment.

The main goals of the NPAR Program were to understand aging and to identify ways to manage aging of safety-related SSCs. The specific technical objectives were to:

- identify and characterize aging effects which, if unmitigated, could cause degradation of SSCs and impact plant safety
- develop supporting data to facilitate management of age-related degradation
- identify methods of inspection, surveillance, and monitoring, or of evaluating residual-life of SSCs, which will ensure timely detection of significant aging effects before loss of safety function
- evaluate the effectiveness of storage, maintenance, repair, and replacement practices in mitigating the effects of aging and diminishing the rate and extent of degradation caused by aging
- provide technical bases and support for the License Renewal Rule and the license renewal process

During the mid-1980s the USNRC initiated two other aging assessment programs as companions to the NPAR Program. One focused on the aging of nuclear plant vessels, piping, steam generators, and nondestructive examination techniques. The other involved the assessment of age-related degradation on plant civil structures. These three



programs provided a wealth of information and insights on aging and aging management that formed the basis for the License Renewal Rule.

The NPAR Program alone produced over 150 technical reports and numerous papers and proceedings concerning aging characteristics and aging management of safety-related SSCs. The major subjects examined by the NPAR and related aging research programs are shown in Table 2.

**Table 2: Subjects Examined by the NPAR and Related Aging Research Programs**

Air operated valves	Chillers
Auxiliary feedwater pumps	Heat exchangers
Batteries	Large electric motors
Bistables/switches	Main steam isolation valves
Cables	Motor operated valves
Chargers/inverters	Piping
Check valves	Power operated relief valves
Civil structures	Small electric motors
Circuit breakers/relays	Snubbers
Compressors	Solenoid valves
Connectors, terminal blocks	Steam generators
Diesel generators	Transformers
Electrical penetrations	Vessels

Although the aging studies examined SSCs with respect to their operation in the nuclear plants, much of the aging degradation and aging management information is applicable to the petroleum and other industrial sectors. A list of selected aging reports from the NPAR program is provided in Attachment of the CGI Report 06-22, *Condition Monitoring of Passive Systems, Structures, and Components*.

Based on industry initiatives started in 1985, two pilot plants were chosen to conduct life extension investigations and feasibility assessments. The principal objectives were to find answers to a number of questions, including:

- What defines the ultimate life of a plant?
- What are the events that lead to final plant shutdown?
- What is a realistic and achievable operating life?
- What type of repair and replacement capital projects would be required?
- Are there any technical or economic obstacles or limits?

These studies introduced the concept of "critical components". These are components that if they were allowed to degrade unimpeded would constitute a safety concern and lead to shutdown. An importance ranking process was developed to identify the critical components and perform a relative importance ranking, using a Delphi process. The result was a list of the top 24 components, all passive components and structures. These components were then selected for a detailed aging assessment to investigate the plausible aging mechanisms, identify the associated aging effects that have been observed and to formulate a strategy for effective aging management, using preventive

and mitigative maintenance or corrective repair and replacement options. These efforts were later extended to cover a host of other components and commodities, including active components, to create a more complete picture of the plant's aging concerns.

While the studies for the two pilot plants were carried out by completely separate research teams, the results and conclusions were very similar. A byproduct of the pilot studies were the identification of a host of additional aging research tasks, a need to better understand certain aging phenomena, the recognition that aging management needs to start at the beginning of the life cycle and the need to perform some maintenance tasks to better monitor material conditions, such as inspections, tests, fatigue cycle counting, measuring environmental conditions in electrical enclosures, testing soil and water for aggressiveness (chlorides, phosphates, pH) with respect to concrete and instituting structures inspections.

A technical review group examined the aging research findings and concluded that many aging phenomena are readily manageable and do not pose technical issues that would preclude life extension for nuclear power plants. They also stated that as long as there are effective inspection and maintenance practices, the plant life is simply limited by the economic cost of repair or replacement of any components that don't meet specified acceptance criteria.

With the technical and economic feasibility of life extension demonstrated, the industry started working with the USNRC to develop a License Renewal Rule that would provide a formal process to allow extended operation beyond the original 40-year license.

In 1991, the safety requirements for license renewal (entitled, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*) were adopted by the USNRC. These requirements, known as the License Renewal Rule, established the procedures, criteria, and standards governing the renewal of nuclear power plant operating licenses. These were made mandatory requirements as part of the United States Code of Federal Regulations (commonly referred to as 10 CFR Part 54).

The scope of this initial version of the Rule included both passive and active components for the safety related systems of the plant.

### ***Revisions to the Rule – Lessons Learned***

Again, the Monticello plant volunteered to be the demonstration plant to test the Rule. The objective was to assess the effectiveness of the requirements and the application and review process. Once completed, it became apparent that the provisions of the original Rule required changing – particularly the requirements for commitments and additional maintenance tasks to be implemented. Cost estimates ranged from to \$100 to \$500 Million for a plant to comply with rule requirements.

The Rule did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which help manage plant aging phenomena on an on-going basis. The initial License Renewal Rule also did not provide a predictable nor

stable process. Industry point out, and the USNRC agreed, that it is essential to have a predictable and stable regulatory process that clearly and unequivocally defines the regulatory expectations for license renewal.

The revised Rule was published in 1995. A copy is provided in Appendix B. The new amended Rule established a regulatory process that is simpler, more stable, and more predictable. It put the focus of the license renewal assessment on the licensees aging management activities concerning passive and long-lived SSCs. It also clarified the focus on managing the adverse effects of aging rather than identification of all aging mechanisms. The changes to the integrated plant assessment (IPA) process were to make it simpler and more consistent with the revised focus on passive, long-lived systems, structures and components.<sup>1</sup>

The relationship of the regulatory requirements for the Maintenance and License Renewal Rules is shown in Figure 4.

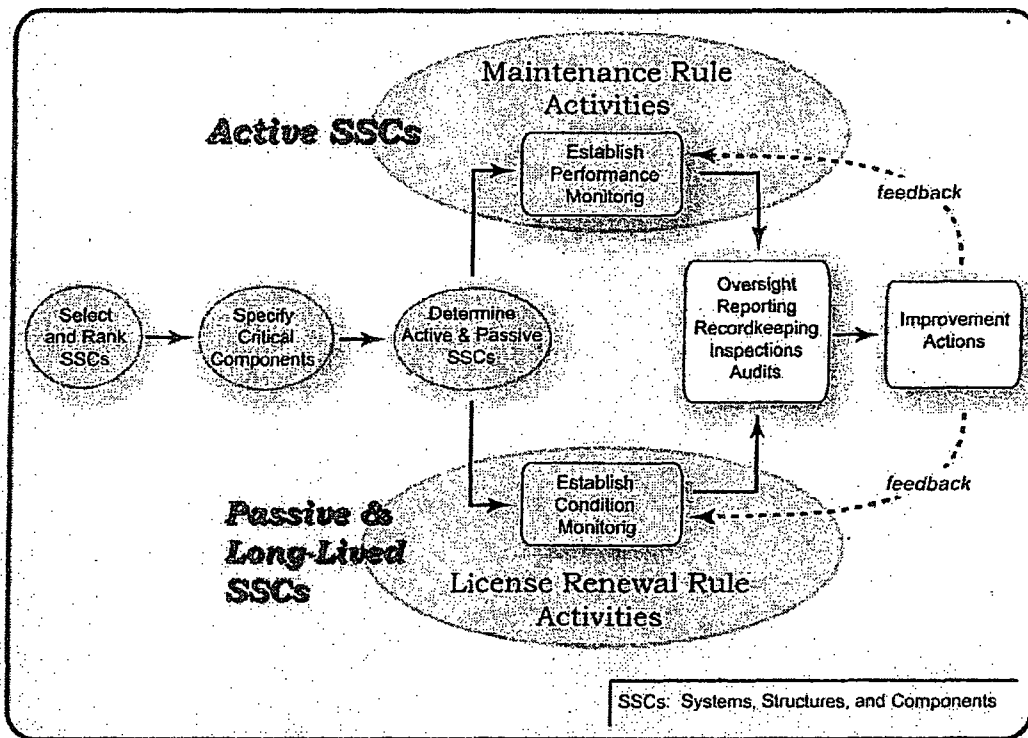


Figure 4: Relationship of Maintenance and License Renewal Rules

### The License Renewal Process

The license renewal process proceeds along two tracks – one for the review of safety issues and another for environmental issues. The safety requirements, as noted above,

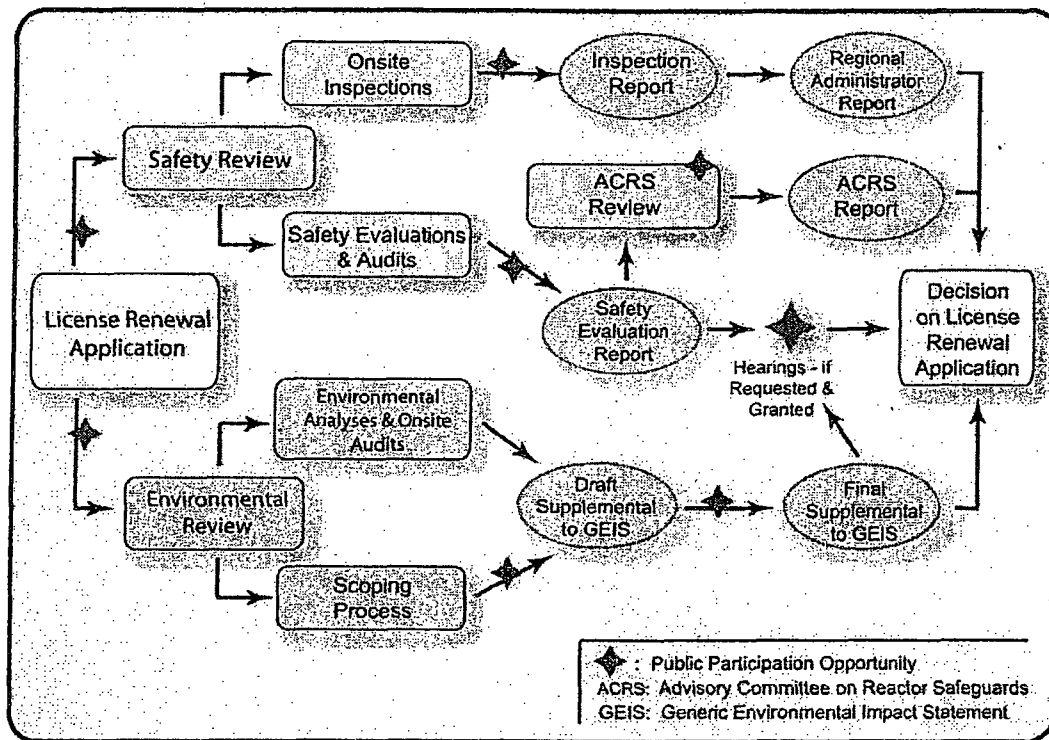
<sup>1</sup> An extensive discussion of the revisions and the USNRC's license renewal philosophy can be found in the Statement of Considerations that accompanied the License Renewal Rule as published in the US Federal Register, Vol. 60, No. 88, page 22461, May 8, 1995.

are addressed in 10 CFR Part 54. The environmental requirements are found in 10 CFR Part 51.

The USNRC developed a generic environmental impact statement (GEIS) which covered impacts that were common to most all nuclear power plants. During the review process the USNRC focuses on the important environmental issues specific to each plant.

The license renewal review process (Figure 5) is intended to identify any additional actions that will be needed to maintain the functionality of the SSCs for the extended operation. The USNRC determined that the following can be excluded from the license renewal aging management review:

- those structures and components that perform active functions
- structures and components that are replaced based on qualified life or specified time period.



**Figure 5:** Simplified Flow Chart of the License Renewal Process (source: USNRC)

### License Renewal Principles

The license renewal requirements for nuclear power plants are based on two key principles:

- the existing USNRC regulatory process (such as the Maintenance Rule) is adequate to ensure that currently operating plants will continue to maintain

adequate levels of safety during extended operation – however, license renewal requirements are needed to address age-related degradation unique to life extension for certain passive and long-lived SSCs as well as a few other issues that may arise during the period of extended operation

- each plant's licensing basis is required to be maintained during the renewal term in the same manner and to the same extent as during the original licensing term

### ***The License Renewal Application***

Two important items that are required to be included in the application are:

- an integrated plant assessment
- an evaluation of time-limited aging analyses

The application development process involves the following actions:

- identification of the SSCs within the scope of License Renewal Rule
- identification of the intended functions of SSCs
- identification of the structures and components subject to aging management review and intended functions
- assurance that effects of aging are managed
- development and application of new aging management programs and inspections
- identification and resolution of time-limited aging analyses
- identification and evaluation of exemptions containing time-limited aging analyses

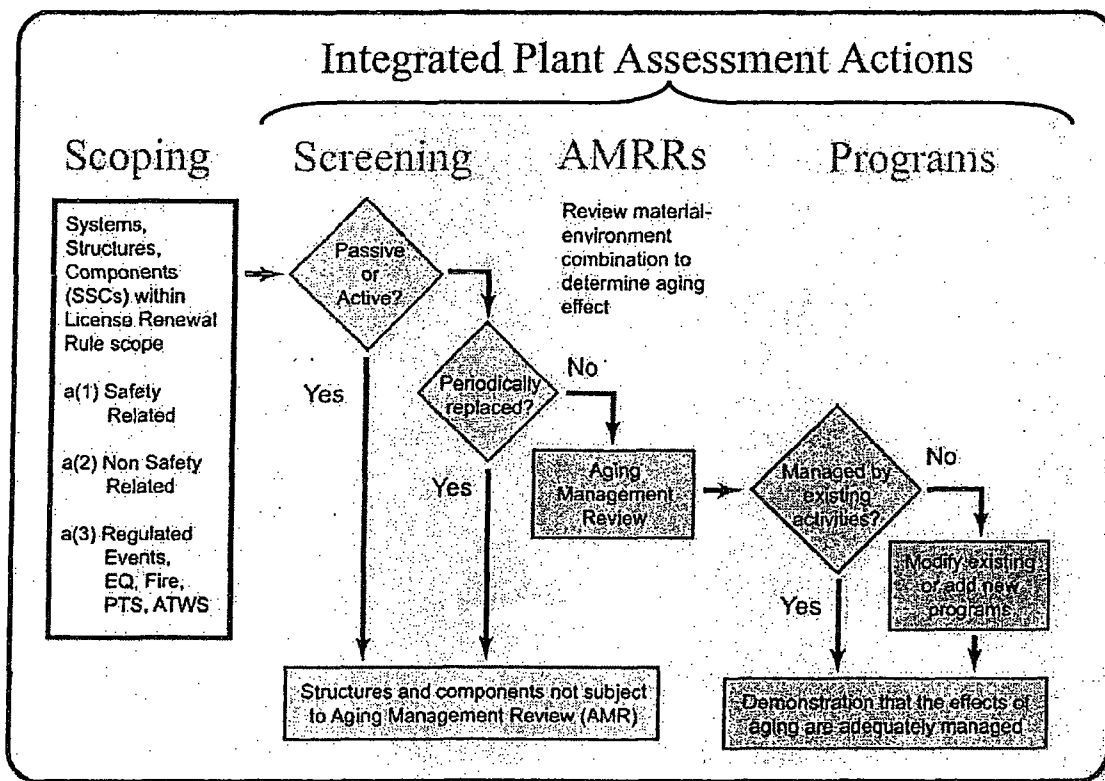
### **Scoping**

The scoping phase requires the licensee to identify all plant systems, structures and components that are safety-related or whose failure could affect safety-related functions, or that are relied on to demonstrate compliance with the several specific USNRC's regulations (such as, for fire protection and plant blackout).

The scoping or categorization process can be rather complicated and requires careful review of the nature and function of the various SSCs being considered. For example in the case of valves and pumps, the valve bodies and pump casings may perform an intended function by maintaining the pressure-retaining boundary and therefore would be subject to aging management review.

### **Integrated Plant Assessment (IPA)**

The integrated plant assessment (IPA) is the core of the license renewal application (Figure 6). The purpose of the IPA is to demonstrate that the structures and components requiring aging management (within the scope of the Rule) have been identified and the effects of aging on their functionality will be managed to maintain an acceptable level of safety during extended operations



**Figure 6: License Renewal Application Activities**

The first part of the IPA process is to determine which of the structures and components within the scope of the Rule are passive and long-lived. Passive structures and components are those that perform their function without a change in configuration or properties. Long-lived items are those that are not subject to replacement based on a qualified life or specified time period. An example list of such structures and components is provided in Table 3.

The objective of this screening exercise is to determine which components and structures require aging management review to determine whether or not some form of aging management is necessary.

There are a number of different techniques that can be used to identify and assess aging effects. The NEI guidance document (NEI 95-10) lists several approved techniques. These include material-environment-stressors analysis, analysis based on common setting or location, plant specific aging analysis based on loss of intended function, and the use of similar aging management reviews approved by the USNRC.

The licensee must demonstrate that the effects of aging will be managed in such a way that the intended functions will be maintained for the extended operation period. Where the licensee can demonstrate that the existing programs provide adequate aging management throughout the period of extended operation, no additional action may be required. However, if additional aging management activities are warranted, it will be

up to the licensee to define these actions. This can include such activities as developing new monitoring programs or increasing current inspections. Licensees should consider all programs and activities associated with the component or structure to determine to what degree they already manage the aging degradation. The four general types of aging management programs are:

- Prevention – to preclude certain levels of aging degradation from occurring (e.g., coating programs to prevent external corrosion of a tank)
- Mitigation – to reduce or slow aging effects (e.g., chemistry programs to mitigate internal corrosion of piping)
- Condition monitoring – to inspect for the presence of and extent of aging effects (e.g., visual inspection of concrete structures for cracking and ultrasonic measurement of pipe wall for erosion-corrosion induced wall thinning)
- Performance monitoring – to test the ability to perform its function (e.g., heat balances on heat exchangers for the heat transfer intended function of the tubes)

**Table 3: Examples of Structures and Components included in, or excluded from, the License Renewal Rule Scope (Source: 10 CFR 54)**

Passive Structures & Components Included in Rule Scope (Example List)	Active Structures & Components Excluded from Rule Scope (Example List)
cable trays component supports containment containment liner core shroud electrical and mechanical penetrations electrical cabinets electrical cables and connections equipment hatches heat exchangers piping pressure retaining boundaries pressurizer pump casings reactor coolant system pressure boundary reactor vessel seismic Category I structures steam generators valve bodies ventilation ducts	air compressors batteries battery chargers breakers circuit boards cooling fans diesel generators motors power inverters power supplies pressure indicators pressure transmitters pumps (except casing) relays snubbers switches switchgears the control rod drive transistors valves (except body) ventilation dampers water level indicators

To assist the licensees in perform their plant-specific aging assessments and avoid duplication of work from one plant to another the USNRC developed a comprehensive guidance document entitled, *Generic Aging Lesson Learned Report (GALL)* NUREG-1801. The document provides aging management matrixes for the various passive mechanical, electrical and structural components found in a nuclear plant. The GALL report also provides links and references to acceptable aging management programs inclusive of specific program attributes. An example of a typical aging matrix from the GALL report is shown in Table 4.

**Table 4: Typical Aging Matrix from GALL Report (Source NUREG-1801)**

NUREG-1801, Rev. 1

VII C1-4

September 20

VII AUXILIARY SYSTEMS C1 Open-Cycle Cooling Water System (Service Water System)							
Item	Link	Structure and/or Component	Material	Environment	Aging Effect/Mechanism	Aging Management Program (AMP)	Further Evaluation
VII.C1-14 (AP-59)	VII.C1.	Piping, piping components, and piping elements	Stainless steel	Lubricating oil	Loss of material/pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis"  The AMP is to be augmented by verifying the effectiveness of the lubricating oil analysis program. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
VII.C1-15 (A-54)	VII.C1.2-a VII.C1.6-a VII.C1.1-a VII.C1.4-a	Piping, piping components, and piping elements	Stainless steel	Raw water	Loss of material/pitting and crevice corrosion, and fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No
VII.C1-16 (AP-56)	VII.C1.	Piping, piping components, and piping elements	Stainless steel	Soil	Loss of material/pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant-specific
VII.C1-17 (AP-30)	VII.C1.	Piping, piping components, and piping elements	Steel	Lubricating oil	Loss of material/general pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis"  The AMP is to be augmented by verifying the effectiveness of the lubricating oil analysis program. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

The licensee has a choice to utilize the generic findings of the GALL report as a technical basis for his plant, subject to verification of applicability. If the plant-specific conditions, materials, components or aging management programs are different, a plant-specific assessment is required. The GALL report relies heavily on a condition directed maintenance program (inspection, analysis and testing) for effective aging management that is to monitor the material conditions.

The aging management programs to be credited for license renewal, must meet a rigorous 10-point acceptance criteria shown in Table 5.

The GALL Report includes a comprehensive listing of all the plausible aging effects and mechanisms, with a definition and explanation of applicability. The basis for these aging effects and mechanisms are contained in the numerous references from the wealth of the aging research conducted by the industry, EPRI, DOE, and the USNRC. With the exception of a few industry-specific or unique degradation mechanisms, these aging effects and mechanisms are applicable to almost any industrial facility and are not specific to power plants. An edited version was extracted from the GALL report is provided in Appendix B.

The last important tool provided with the GALL report, is a series of aging management programs (AMPs), targeting the specific aging mechanisms and affected materials. Licensees are expected to implement these aging management programs as part of their maintenance program without much deviation. If plant-specific changes are required, they must be identified to the USNRC for approval. Each of the aging management programs has been developed with substantial industry input to reflect current aging



**Table 5: Aging Management Activity Program Elements** (Source, NUREG-1801)

Element	Description
1. Scope of the activity	Scope of the program/activity should include the specific structures and components subject to an aging management review for license renewal.
2. Preventive actions	Preventive actions should mitigate or prevent aging degradation.
3. Parameters monitored or inspected	Parameters monitored or inspected should be linked to the degradation of the particular structure or component intended function(s).
4. Detection of aging effects	Detection of aging effects should occur before there is a loss of structure or component intended function(s). This includes aspects such as method or technique (i.e. visual, volumetric, surface inspection), frequency, sample size, data collection and timing of new/one-time inspections to ensure timely detection of aging effects.
5. Monitoring and trending	Monitoring and trending should provide predictability of the extent of degradation and provide timely corrective or mitigating actions.
6. Acceptance criteria	Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the structure or component intended function(s) are maintained under all current licensing basis design conditions during the period of extended operation.
7. Corrective actions	Corrective actions, including root cause determination and prevention recurrence, should be timely.
8. Confirmation processes	Confirmation processes should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
9. Administrative controls	Administrative controls should provide a formal review and approval process.
10. Operating experience	Operating experience of the aging management activity, including past corrective actions resulting in program enhancements or additional programs or activities, should provide objective evidence to ensure that the effects of aging will be adequately managed so that the intended functions of the structure or component will be maintained during the period of extended operation.

management practices and to maintain effectiveness. There are 39 AMPs for mechanical component aging management, eight structural programs and six electrical programs. An example of an aging management program for concrete structures is provided in Appendix D.

As with the aging mechanisms and aging effects, the AMPs are equally applicable to other industrial facilities, with perhaps a minimized formality and quality control.

Much of the contents contained in the GALL report are repeated in a companion document called the License Renewal Standard Review Plan (SRP-LR), NUREG-1800. This document is for the use by the USNRC staff to assist in the review of the License Renewal applications and to assure consistency among the reviewers. The SRP-LR also provides guidance regarding components, aging mechanisms and aging effects not addressed in the GALL but which require plant-specific aging evaluations.

While the aging management programs are not mandatory, they represent one acceptable method to perform effective aging management under the license renewal rule. Licensees may deviate and apply their own versions. However, such programs are subject to acceptance by the USNRC and usually require a substantial justification to deviate from the standards. In this way, the AMPs constitute a near-mandatory status and the specific activities referred to the programs, become licensing commitments for

the extended operating period. For components that are not covered by the GALL report or for which no standard AMPs are applicable, the applicant must perform a detailed documented aging management review.

For the typical plant, the aging management review resulted in the identification of about 200 to 400 specific aging management activities. The activities range from completely new programs to changes to existing programs (scope for additional components, more frequent inspections, different technology, new locations, etc) and administrative tasks to document activities, quality control and training. Most of the impact comes from the additional inspections and testing requirements to monitor the degradation and engineering analyses to demonstrate that existing design margins have not eroded and are adequate for the extended operating period. Examples of updated and new aging management activities and programs are shown in Table 6.

**TABLE 6: Typical New and Updated Aging Management Activities and Programs**

<b>Updated Programs (examples):</b>	<b>New Programs (examples):</b>
Boric Acid Corrosion Prevention Program	Alloy 600 Aging Management Program
Fire Protection Program	Buried Piping Inspection Program
Instrument Air Quality Program	Cast Austenitic Stainless Steel (CASS) Evaluation Program
Maintenance Program	Heat Exchanger Monitoring Program
Service Water System Reliability Program	Cable Management Programs
Structures Monitoring	Reactor Vessel Internals Programs
System Testing Program	Small Bore Piping Program
System Walkdowns Program	Wall Thinning Monitoring Program
	Water Chemistry Control - Chemistry One-Time Inspection Program

#### **Time Limited Aging Analysis**

One of the major provisions of the Rule is the identification and analysis of Time Limited Aging Analyses (TLAA). The licensee must identify and update time-limited aging analyses. During the design phase for a plant, certain assumptions about the length of time the plant will be operated are incorporated into design calculations for various SSCs. In order to obtain approval for a renewed license, these calculations must be shown to be valid for the period of extended operation, or the affected SSCs must be included in an appropriate aging management program.

In essence, the USNRC requires the licensee to go back to the original plant design documents and determine if the design criteria included specific time limited assumptions or criteria. Once identified, the original calculations or qualification tests must be updated for the new extended operating life. This process may be a simple ratio method to establish a new value for fatigue cycles, or it may involve a complex fatigue analysis, considering the used-up cycles and extended operating life.

A comprehensive review was performed by the industry to identify potential time limited aging analyses (TLAAs) that may be part of the original design basis, the underlying design codes and standards, and the qualifications tests (i.e. environmental exposure of cables, corrosion tests) that were performed in support of the original design life calculations. The principal issues identified by this industry review are (NUREG-1800 & NEI-95-10):

- reactor vessel neutron embrittlement
- prestressed concrete containment tendon prestress
- metal fatigue
- environmental qualification of electrical equipment
- metal corrosion allowance
- inservice flaw growth analyses
- inservice local metal containment corrosion
- high-energy line break postulated on fatigue cumulative usage factor

Once the licensee has identified their specific TLAA's, analysis must be performed to extend the design basis for the extended operating period or compensatory measures must be implemented. The licensee must demonstrate one of the following:

- The analyses remain valid for the period of extended operation or;
- The analyses have been projected to the end of the extended period of operation; or
- The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

These options clearly include full or partial replacement of the component, requalification by testing, more sophisticated analyses (i.e. finite element analysis and fracture mechanics) or use of mitigative measures to impede or avoid degradation. Some plants have chosen to implement stricter preventive and predictive maintenance, one-time inspections to assess used-up margins, monitoring of the environments to recalculate cable life, new inspections to quantify degradation and installation of coupons to monitor corrosion and cracking.

## **The Maintenance Rule**

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Because active components in mechanical and electrical systems are normally operating, their performance can be monitored and trended to detect incipient degradation. Representative parameters that can be measured must be established for both the local components and for the complete system. Examples of local component parameters include flow, differential pressure, vibration, and delta temperature. Reliability and availability are examples of typical system performance parameters.

Within the nuclear power generation industry in the United States, the US Nuclear Regulatory Commission (USNRC) has promulgated a "Maintenance Rule" for the purpose of improving the performance monitoring of critical systems at all nuclear power plants in the United States.

### ***Regulatory Requirements***

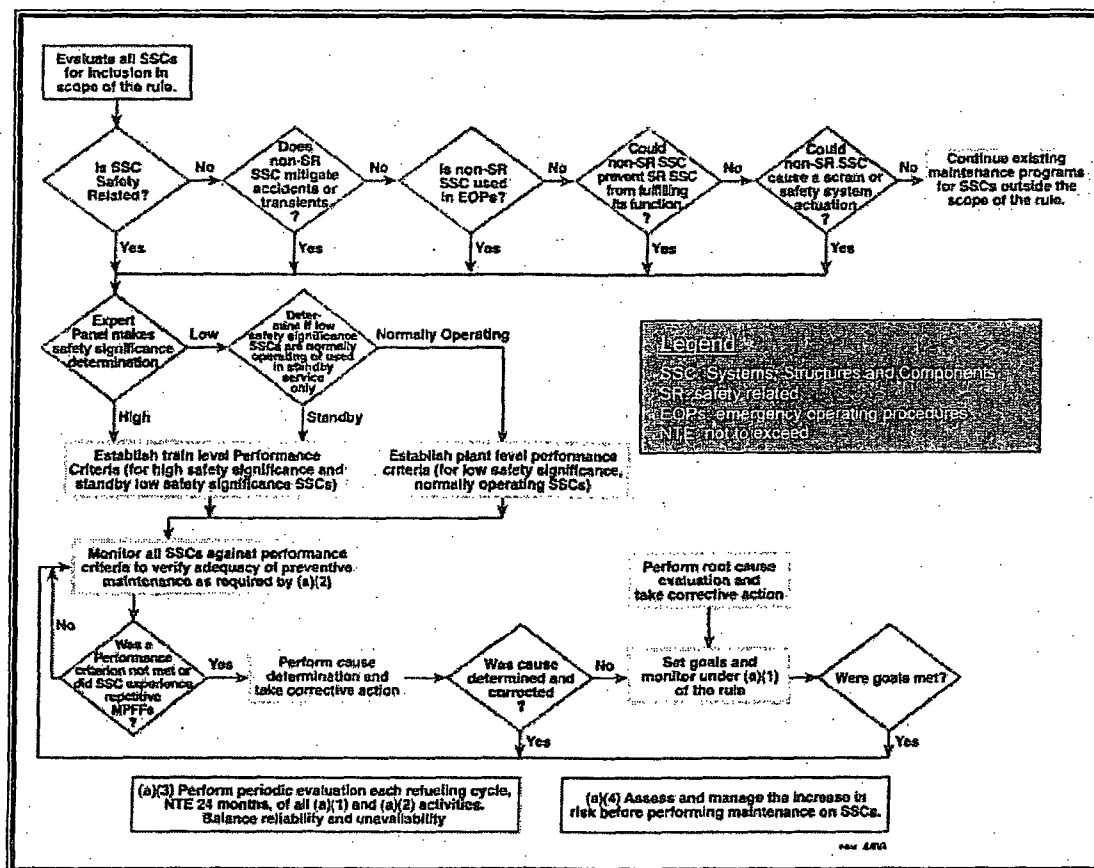
During the 1980s, the USNRC became concerned with the maintenance of nuclear power plants and the attendant decline in reliability. No regulatory provisions were in force to require uniform application of maintenance, except for the Technical Specifications, which required periodic surveillance testing, and the ASME Code, which required periodic inspections of the safety-related pressure boundary components. With the assistance of a number of volunteer plant owners, the USNRC conducted a survey of utility practices in an effort to establish the effectiveness of various maintenance programs (i.e. experience based, vendor recommended, preventive, corrective, run-to-failure), allocation of utility resources among safety and non-safety (power production) equipment and utility methods of monitoring and benchmarking performance. The survey results led the USNRC to conclude that more consistent and rigorous monitoring and reporting of individual system performance parameters was needed. Using industry input, the USNRC developed a performance-based regulation that would allow individual plants to define the scope of the program, the performance parameters and the acceptance criteria. The plant specific application and implementation would be subject to inspection by the USNRC. The original Rule was issued in July 1991 and became effective in July of 1996 and the USNRC began their implementation inspections. The Rule was revised a number of times to incorporate lessons learned, clarifications and new requirements.

### ***The Maintenance Rule Provisions***

The Maintenance Rule was issued under the United States Code of Federal Regulations. This is a mandatory rule that all commercial nuclear power plants must follow. A copy of the full text of the Maintenance Rule is provided in Appendix A. Although the Rule consists of only a single page, the underlying documentation, interpretations, and guidance reports amounts to thousand of additional pages of material and information.

The Maintenance Rule analysis process is shown in Figure 7.

Figure 7: Simplified Flow Chart of the Maintenance Rule (Source: USNRC)



The key provisions of the Rule are:

- defining systems monitoring requirements
- preventive maintenance versus availability/reliability
- corrective action goal setting
- operating experience considerations
- demonstrations of preventive maintenance (PM) effectiveness
- bi-annual performance reviews
- quantification of on-line risk

### Systems Monitoring Requirements

The Rule makes a significant distinction between important systems that need to be performance monitored at the train level and those systems that can be monitored at the plant level. The systems that are considered to be safety significant with equally or diversely redundant safety systems typically have two or three trains or channels.

Standby systems (systems that are activated in response to an accident or fire or are required to mitigate accident consequences) are monitored using reliability as a

performance parameter. Reliability can be measured by such indicators as fail-to-start or fail-to-run per 100 attempts.

Normally operating systems are monitored using availability as a performance measure. Availability is determined as the fraction of system available hours during the mission time divided by the mission time. When assessing reliability and availability, the success or ability of accomplishing the defined safety functions is considered. This permits some level of degradation, as long as the system's functions are not compromised.

#### **Preventive Maintenance versus Availability/Reliability**

The Rule recognizes the conflict between performing preventive (invasive) maintenance that requires the system or component to be removed from service and the need to maintain satisfactory availability and/or reliability. One of the requirements mandates that an adequate balance of the two be maintained and reported.

#### **Corrective Action Goal Setting**

If a system cannot meet its performance criteria over a period not exceeding 24 months, corrective action is required and a new and more specific performance criteria must be established (Goal Setting) to demonstrate that the corrective action has been effective. This Goal Setting assures that recurring problems are fixed.

#### **Operating Experience Considerations**

Operating experience must be considered when establishing the performance parameters and criteria. This experience may be based on generic industry experience or the historical plant performance, failure rates, or reliability / availability values assumed in the plant's probabilistic risk analysis (PRA).

#### **Demonstrations of PM Effectiveness**

Systems that are monitored at the plant level require demonstration that the preventive maintenance programs are effective. Plant level performance criteria can include repetitive failures, plant shutdowns, initiation of safety systems and lost production. If the established criteria levels are exceeded, the system must be elevated to "system level monitoring".

System level monitoring requires that an elevated level of monitoring must continue until it can be demonstrated that the system has achieved its new system level performance, before the system is returned to plant level.

#### **Bi-Annual Performance Reviews**

The result of the system monitoring and trending activities is subject to bi-annual review to highlight the:

- performance problems
- corrective actions taken
- changes in performance parameters or criteria

- assessment of the balance between maintenance outages and system availability
- evaluation of industry operating experience

The evaluation of industry operating experience is an attempt to identify precursors or incipient failures that may have occurred at other plants and may have generic implications.

### **Quantification of On-Line Risk**

A new paragraph was added to the Rule in 2000 to address the risk associated with plant configuration changes made during operation. This includes systems that are taken out-of-service for maintenance or due to failure/degradation. The on-line risk is influenced by the importance of the unavailable system, the period of time that it is not available, as well as the status of other safety related systems. As a consequence, the USNRC now requires that the on-line risk must be quantified to support continued operation of the plant.

### ***Modifications/Improvements to the Rule***

Following the original issue of the rule in 1991, the Nuclear Energy Institute (NEI) formed a utility task group to develop an industry guide, NEI-93-01, to assist the plants with the implementation. The USNRC conducted a number of early plant implementation audits in 1996 and based on these audits it was determined that some interpretations and improvements were desirable. The nuclear industry, represented by the Nuclear Energy Institute (NEI), discussed the implementation issues with the USNRC and subsequently generated a Revision 1 to NEI-93-01 in 1996.

The USNRC reviewed the revised NEI-93-01 for generic acceptability. In 1997 the guide was endorsed with some additional provisions (USNRC Regulatory Guide 1.160 Revision 2). The most significant addition was the inclusion of structures including concrete and steel structures that house or protect equipment covered within the scope of the Rule.

In 2000 the Rule was modified again to address on-line risks associated with maintenance activities. The USNRC added a new paragraph A-4 that then required the NEI to revise NEI-93-01. The new Section 11 provides guidance to the industry on how best to assess on-line risk associated with their maintenance activities. The USNRC endorsed the changes to NEI-93-01 in the USNRC Regulatory Guide 1.180.

### ***Regulatory Inspections and Guidance***

The USNRC started plant-specific inspections and audits in 1996 and 1997 to verify the acceptability of methods and procedures and the programmatic approaches taken. Because the rule is performance based, these inspections were unique and required substantial guidance and training of the inspector teams. The training guides and inspection procedures were made available to the industry. This allowed self-assessments and readiness reviews to be conducted prior to USNRC on-site inspections. Lessons learned from the inspections were communicated to the industry in a number of workshops and seminars.

### ***Monitoring Issues***

Monitoring important systems at the train level is considered an effective way to identify poorly performing equipment. A redundant high performance train could otherwise shadow the poorly performing train. Performance monitoring at the train or channel level is therefore mandated for risk significant systems. The USNRC was also concerned that generic problems in cross-system component groups (valves, motors, pumps, solenoids) would not be readily identified. As a result all plants are now tracking functional failures, which are periodically reviewed to identify trends of multiple component failures. A definition for a "Repetitive Functional Failure" was crafted to include: "Failures of another same component with identical cause".

Determining meaningful performance parameters for structures became a difficult task. A "Structures Monitoring Program" was created and implemented to periodically inspect (i.e. five to ten year intervals) for functional degradation. The acceptance criteria were defined in the American Concrete Institute (ACI) standards or the American Institute of Steel Construction (AISC) standards. If performance problems are identified, corrective action is required and the structure must be re-inspected at shorter intervals until it can be demonstrated that the fix was effective.



## Industry Aging Management Programs (PM Basis and LCM)

### *The EPRI PM Basis Program*

Recognizing the license renewal and maintenance rules as effective aging management tools for the safety-related systems and components in the plants, the industry needed to develop commensurate programs to be applied for the traditional part of the plants, the power production equipment. It is obvious that these systems must also undergo a transformation to support an extended operation. The first of these comprehensive efforts was the development of the Preventive Maintenance Basis Program (PM Basis) by EPRI to cover the majority of generic components and commodities found in the plants. The objective was to research and document the "Industry Best Practices" with respect to effective maintenance and aging management practices. Previously, plant maintenance was largely based on the equipment vendor recommendations, often without a solid technical basis for the requirements, except to protect the equipment warranty provisions.

**Table 7: EPRI PM Basis Component Listing**  
(Source EPRI TR106857)

Component Description	Volume
Air Operated Valves	V1
Medium Voltage Switchgear	V2
Low Voltage Switchgear	V3
Motor Control Centers	V4
Check Valves	V5
Motor Operated Valves	V6
Solenoid Operated Valves	V7
Low Voltage Electric Motors (600V and below)	V8
Medium Voltage Electric Motors (between 1kV and 5kV)	V9
High Voltage Electric Motors (5kV and greater)	V10
Direct Current Electric Motors	V11
Vertical Pumps	V12
Horizontal Pumps	V13
Reciprocating Air Compressors	V14
Rotary Screw Air Compressors	V15
Power Operated Relief Valves - Solenoid Actuated	V16
Power Operated Relief Valves - Pneumatic Actuated	V17
Pressure Relief Valves - Spring Actuated	V18
HVAC - Chillers and Compressors	V19
HVAC - Dampers and Ducting	V20
HVAC - Air Handling Equipment	V21
Inverters	V22
Battery Chargers	V23
Battery - Flooded Lead-Acid	V24
Battery - Valve-Regulated	V25
Battery - Nickel-Cadmium (NICAD)	V26
Liquid-Ring Rotary Compressor and Pump	V27
Positive Displacement Pumps	V28
Relays- Protective	V29
Relays- Control	V30
Relays- Timing	V31
Heat Exchangers	V32
Feedwater Heaters	V33
Condensers	V34
Main Feedwater Pump Turbines	V35
Terry Turbines	V36
Main Turbine EHC Hydraulics	V37
Transformers- Station Type Oil Immersed	V38
I&C Components	V39

The PM Basis program initially included 39 component templates, each documented in a separate report volume (see Table 7). The program scope was later expanded to add a variety of instrumentation groups. For each component, the program determined the appropriate maintenance activities, the recommended frequency for the activity and the effectiveness of the action. The program also provided a first attempt at correlating PM frequency with reliability, i.e. the more often a component is tested or inspected, the more reliable it is supposed to be and the corollary, what is the reliability reduction if the PM task is eliminated. In many cases, a single task will not provide a major improvement in reliability, but a combination of PM tasks can make a major difference.

In addition to the individual component reports, EPRI converted the templates to electronic format, so that they can be accessed via computer and component reliability manipulations can be exercised on the ACCESS based software. The best practices are captured on a summary template for each component. The templates recognize the fact that not all components are of equal importance and therefore the level of preventive maintenance may be significantly different, dependant on the components service duty, environmental exposure and functional importance. The different levels of recommended PM for the various categories (there are eight different categories to choose from) are shown on the templates. An example template for large electric motors is shown in Figure 8.

### *The Life Cycle Management Planning (LCM) Process*

The Life Cycle Management planning methodology was developed under EPRI and utility sponsorship to create a tool for the long-term maintenance planning, using both, technical and economic measures to find the maintenance plan that will give the highest reliability at the lowest cost. The LCM process is fairly complex in that it requires a relatively accurate representation of the plant's historic performance, component failures, failure consequences, such as lost power generation, regulatory scrutiny, corrective maintenance costs, and the impact of a poor plant performance on the corporate image and financial picture. However, given the eventual possibility that the

**Figure 8: EPRI PM Basis Template Example**

ate: Motor - Medium Voltage - <15kV - Form

PM Basis Definitions Vulnerability Task Ranking Source Main

To View Template Definitions Click Anywhere To The Right

Motor - Medium Voltage - <15kV

Duty Cycle: H.T. L.O. H.T. L.O. H.T. L.O. H.T. L.O.

Service Conditions: SEVERE MILD SEVERE MILD

Task Name	CHS	CLS	CHM	CLM	NHS	NLS	NHM	NLM
Thermography	6M	6M	6M	6M	6M	6M	6M	6M
Vibration Monitoring	3M	3M	3M	3M	6M	6M	6M	6M
Oil Analysis And Lubrication	6M	6M	6M	6M	1Y	1Y	1Y	1Y
Electrical Tests - On-line	6M	1Y	6M	1Y	1Y	2Y	1Y	2Y
Mechanical Tests - On-line	3M	6M	3M	6M	6M	1Y	6M	1Y
Electrical Tests - Off-line	2Y	4Y	2Y	4Y	4Y	4Y	4Y	4Y
Mechanical Tests - Off-line	2Y	4Y	2Y	4Y	3Y	5Y	3Y	5Y
System Engineer Walkdown	3M	3M	3M	3M	3M	3M	3M	3M
Mechanical Refurbishment	AR	AR	AR	AR	AR	AR	AR	AR
Refurbishment	10Y	15Y	10Y	15Y	10Y	20Y	10Y	20Y
Operator Rounds	1S	1S	1S	1S	1D	1D	1D	1D

plants will operate for 60 years or longer, it was necessary to change the maintenance planning horizon and to be able to forecast major capital projects with respect to timing and cost for the foreseeable future. The following is a quote taken from the EPRI summary report for LCM planning:

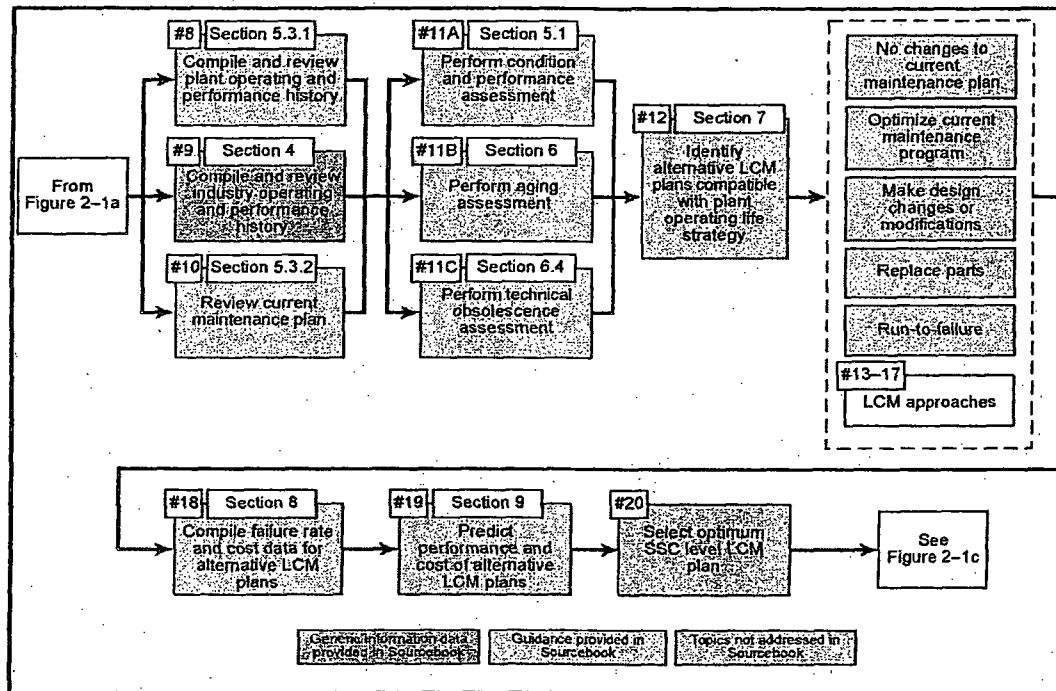
“Life Cycle Management planning is intended to provide an effective long-term planning tool for minimizing unplanned capability loss and optimizing maintenance programs and capital investments consistent with plant safety and an identified plant operating strategy. Such an operating strategy might include license renewal and/or plant power uprating. An LCM Plan addresses such issues as aging management, preventive maintenance, obsolescence, and the replacement or redesign of a structure, system or component (SSC) important to safety and plant operation. In short, LCM Planning is viewed as a viable process to systematically identify and examine the important SSCs, optimize their contribution to plant performance, reliability, safety and value, and prepare long-term maintenance management plans and resource projections.”

The basic steps of the LCM process are delineated on the simplified diagram, shown in Figure 9. The major steps are briefly reviewed to help understand the interrelationship and task objectives.

### Compiling Performance and Operating History

Some plants have included cost data in their WO database, which when trended over time, provides an additional parameter to measure maintenance effectiveness. More money does not always lead to better reliability. To benchmark the plant's performance, similar operating data, including generic failure rates, is assembled from the EPIX

Figure 9  
LCM Planning Flowchart – Technical and Economic Evaluation



database and other sources (such as the French EDF Eireda database). Benchmarking has the principal objective to place the specific plant performance relative to its peers. If the plant experiences a failure rate of twice the industry average, there is ample room for improvement and investments are economically justified. If the plant turns out to be already a leader in performance, additional improvements are difficult to sell.

Another aspect of this performance compilation task is the review of the plant's maintenance programs and procedures and to compare the list with the industry "Best Practices", such as the EPRI PM Basis Templates, to identify specific shortcomings and gaps that can be closed to enhance the plant performance.

### **Condition Assessment**

In order to establish a baseline for the plant's equipment performance and reliability, the operating history over the last 5 to 10 years is reviewed and trended. Typically, the plant will have a work order database from which the preventive and corrective work orders can be accessed. A simple count per year will provide a meaningful trend to see if the maintenance activities are increasing, decreasing or portray a stable trend. Also, the ratio of preventive to corrective work orders will provide some indication for a successful maintenance program (corrective work orders are decreasing), or the trend will point to problems, that is failures are increasing as an indication of progressive aging problems.

The age of the plant can have a profound effect on the performance and condition of its components; therefore it is necessary to have a good understanding of the material condition of the components at the time the assessment is made. Material conditions are determined from the review of maintenance history, such as inspection reports, test data, diagnostic data, craft feedback, spare parts use, operating records and a plant walkdown. From this an estimate can be rendered if the plant age is commensurate with its condition, that is, if its useful life has been expended faster than expected or the current condition is better than anticipated.

### **Aging Evaluation**

Next is the aging evaluation to be performed for each major component or commodity group. Here the work performed by the industry groups and USNRC in support of the license renewal represents a basis to start the assessments. Typically a matrix is constructed, showing the basic component parts and materials, their applicable aging effects and associated aging mechanisms and the effective aging management programs. A typical aging matrix (this one for electric motors) is shown in Table 8.

For each line item, the plant's matching aging management program is identified and reviewed to determine if the effective attributes are included and to highlight any gaps that need to be addressed. The previous review of the operating history and plant condition records also contributes to this task to ascertain applicability and to assure that plant specific conditions are not overlooked.

**Table 8: Typical Aging Management Evaluation Matrix (Electric Motor)**

Structure or Components	Component/ Material Grouping	Plausible Aging Effects	Potential Aging Mechanisms	Present Plant Aging Management Programs
Rotor and Stator Windings End turns	Copper and Insulation	Discoloration, Burning, melting	Winding Shorts, Moisture Intrusion, Aging, Dirt, High Temperature	Motor Status Monitor. Refurbishment Consider internal inspection
		Overheating	Aging, Dirt	See above
Rotor Bars	Steel	Loose	Vibration, Age, Fatigue	Vibration monitoring On-line electrical tests
Rotor Shaft	Steel	Deformation, cracking	Vibration, fatigue, corrosion	Vibration monitoring. Bearing temp. monitoring Internal visual inspection
Bearings	Various	Loss of Material, Cracking	Friction, Wear, Loss of lubrication	Vibration monitoring Temperature monitoring Oil sampling, analysis Thermography Internal inspection
Wiring, Terminations	Copper, Insulation	Loss of Contact, Cracking	Pinched, crimped, loose wire, Aging, corrosion	Thermography Visual inspection High pot tests
Frame, Base Plate	Carbon Steel	Loss of Material, Cracking, Deformation	Corrosion, Vibration, Loose Bolts	Vibration monitoring Visual inspections Recoating MR Structures Monitoring
Cooling Coils, Oil and water piping/reservoirs	Carbon Steel, SS	Leakage, Cracking	Corrosion, Wear, Vibration, Fatigue	Oil sampling, testing Visual inspection (E/I) Operator/SE rounds
Oil sight glass, Oil seals	Various non-metallic	Leakage	Corrosion, aging, wear, fatigue	Visual inspection Operator/SE rounds Periodic replacement
Sensors (RTDs, TCs, LVDTs, level, pressure, DP)	Various	Loss of signal, Drifting	Vibration, aging, corrosion	Calibration Replacement
Space heaters	Copper, insulation	Loss of continuity	Loose, broken wire, Moisture accumulation	Winding temp. monitoring Functional testing Thermostat calibration

### **Obsolescence Assessment**

An obsolescence assessment provides a critical review of the potential technical obsolescence of the equipment. The industry is experiencing a serious exodus of original equipment vendors, many vendors do no longer support warranty and equipment services or have terminated production of spare parts. This puts the plant into a vulnerable position, leaving few of acceptable options, including re-engineering or reverse engineering, substituting newer models that often do not fit the original configuration envelope, upgrading technology (analog to digital) creating electronic-computer interface problems or scavenging parts from abandoned plants. The obsolescence assessment criteria and the relative ranking applied by a number of plants are shown on Table 9.

The first step is to assess the exposure level to obsolescence. Typically the electrical-electronic and instrumentation and control components are affected most prominently.

Obsolescence is ranked by applying a set of questions and ranking the applicability of each question. The total numerical value is compared to a traffic light scale to indicate the eminence of obsolescence. While this may not be a true scientific process, it nevertheless provides a timeframe for corrective or mitigative action.

The "traffic light" ranking for obsolescence is:

- Total Score is < 6.0, RED and the SSC obsolescence is serious. Potential options to deal with obsolescence and contingency planning should be identified. Guidance on the modeling, timing and costs of these contingencies and the associated risks should be provided.
- Total Score is between 6.0 and 10.0, YELLOW and the SSC may have longer-term concerns for obsolescence. Contingency planning and options should be considered.
- Total Score is > 10, GREEN and the SSC is not likely affected by obsolescence.

**TABLE 9: Technical Obsolescence Evaluation Criteria (Breakers)**

Technical Obsolescence Evaluation Criteria		Base Score Yes=5 No=0	GE AKR	GE AM	W DHP	ABB K- line
1	Is the SSC still being manufactured and will it be available for at least the next five years?	5	0	0	0	5
2	Is there more than one supplier for the SSC for the foreseeable future?	3	0	0	0	0
3	Can the plant or outside suppliers manufacture the SSC in a reasonable time (within a refueling outage)?	3	0	0	0	3
4	Are there other sources or contingencies (from other plants, shared inventory, stock-piled parts, refurbishments, secondary suppliers, imitation parts, commercial dedications, etc) available in case of emergency?	3	3	3	3	3
5	Is the SSC frequency of failure/year times the number of the SSCs in the plant times the remaining operating life (in years) equal or lower than the number of stocked SSCs in the warehouse?	3	0	0	0	0
6	Can the spare part inventory be maintained for at least the next five years?	3	3	3	1	3
7	Is the SSC immune to significant aging degradation?	1	0	0	0	0
8	Can newer designs, technology, concepts be readily integrated with the existing configuration (hardware-software, digital-analog, solid-state, miniaturized electronics, smart components, etc)?	3	1.5	0	3	3
<b>Total Obsolescence Score</b>		<b>24</b>	<b>7.5</b>	<b>6</b>	<b>7</b>	<b>17</b>

### **Determining LCM Planning Options and Plant Strategies**

At this point in the LCM planning process, all the potential enhancements should be identified, such that a concise list of new or modified maintenance activities can be compiled, along with their costs and timing of implementation. Each goal can be met by a number of different options, called Alternatives in the LCM process. The Alternatives include:

- **Maintain the Current Maintenance Program**  
This is considered the base case against which other options are compared. The model assumes that current maintenance practices are continued and failure rates will gradually increase commensurate with progressive aging. Equipment replacement at time of failure is the planned corrective action.
- **Optimize the PM Program**  
Low cost PM activities are implemented on the basis of their cost effectiveness. Existing tasks are fine tuned or modified to be more effective and tasks with little payback are eliminated. A variant to the PM program is preventive replacement of components that have reached their predetermined useful life.
- **Make Design Changes and Modifications**  
Typically this option is a more costly alternative and makes sense for long-term operation if the design change avoids costly failures and lost power generation. There is a caution though in that design changes are often not proven concepts and may turn out worse for the plant.
- **Designate Components as Run-to-failure**  
For many unimportant components this is a reasonable alternative. In order to be effective, there must be a task that determines when failure has occurred so that a replacement can be installed.

Plant operating strategies need to be established, such that the LCM planning can consider the appropriate planning horizon, which is the remaining operating life, whether the plant is base loaded or cycled and if a power uprate is contemplated.

### **Economic Analysis of LCM Alternatives**

The last step of the LCM process is to consolidate the technical data, failure data and financial/cost data to be loaded into financial analysis software, called LcmVALUE, to perform the Net Present Value (NPV) and Benefit to Investment Ratio (BIR) calculations that provide the measure of economic feasibility. The Alternative with the lowest NPV cost and the highest BIR is the preferred option. If the results are very close (i.e. within 1% of each other) additional sensitivity and uncertainty analysis are typically performed to render a confident recommendation. Results are highly dependant on long-term financial assumptions (such as discount rate, inflation rate, cost of power generation, cost of labor/materials, etc) and small changes cause large fluctuations in the results.

### ***The Use of Probabilistic Risk Analysis for Maintenance***

The probabilistic risk analysis (PRA) was initially developed for the safety related part of the nuclear power plant to facilitate simulation of various accident scenarios. Over time, plant-specific failure data became available and Bayesian updating brought about much more accurate modeling of the plant. With the promulgation of the Maintenance Rule, the PRA was expanded to now also include the power generation part of the plant, such that on-line risk modeling has become feasible and is performed on a routine basis. Outage times associated with preventive maintenance and surveillance testing as well as unanticipated equipment failures (emergent events) can be modeled and the risk impact associated with maintenance activities can be assessed on a continual basis. As plants continue to age, the increased equipment failures, if any, will be captured and the overall plant risk changes will have to be managed within the acceptance limits. This is another form of aging management trending at a higher level.

This PRA fidelity has led to new uses of the PRA, including risk ranking (RRW and RAW) of individual systems, evaluation of configuration and design changes prior to actual implementation and risk informed inspection plans (locations and frequency). Most recently, the USNRC has issued guidance for plant owners to apply PRA to fire protection and quality assurance programs.



## Regulatory and Industry Aging Research

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### *Early EPRI Pilot Plant and Demonstration Projects for License Renewal*

As noted previously, the EPRI and DOE co-sponsored life extension pilot plant projects were initiated to study the feasibility and boundaries of nuclear plant life extension beyond the licensed 40-year life. With the new construction of power plants virtually coming to a halt after the 1979 Three Mile Island event, the electric generation industry and the US Department of Energy (DOE) were looking at long-term solutions to a looming energy crisis. Extending the plant life by some 20 years is equivalent of building 50 new power plants. The objectives of these early studies, as quoted in the Phase 1 BWR Pilot Plant Life Extension Report were:

*To determine a realistic life goal for BWR plants, to identify major degradation mechanisms and potential technical obstacles to life extension, and to provide a methodology for BWR life extension programs.*

As the project was nearing completion and confidence in life extension was assured, economic obstacles and limits became an additional concern, as the list of potential new aging management activities and component replacements grew. The projects did develop the concept of "Critical Components" to delineate those that are essential to function and must be carefully managed to achieve the new life goals. It was also discovered that steel and concrete structures are not immune to aging and require aging management, largely through preventive techniques such as sealing, protective coatings and cathodic protection.

With the success of the pilot plants, a Phase 2 project was initiated to begin aging assessment of most of the plant components and commodity groups (cable, piping, structures, pressure boundary components, batteries, diesel generators, power generation equipment, etc). Among the top twelve critical components, all but two were passive components, the control center and diesel generators being the only active components. The Phase 2 report laid the foundation for identifying potential aging effects and mechanisms, their rate of degradation, manifestation of degradation and vulnerable locations. The studies also provided a first glance at potential aging management tactics from preventive/predictive maintenance, mitigation techniques, replacement options and repair feasibility.

The demonstration projects were initiated following the USNRC promulgation of the original License Renewal Rule in December 1991. The principal objective was to test the Rule's provisions and to generate the first license renewal application. It turned out not to be feasible and became unworkable in addition to plant owners concerns for an unstable licensing environment with open interpretation of the actual requirements. The license renewal application was never filed and the action prodded the NRC to revise and simplify the rule in 1995.

### ***DOE-Sandia Aging Management Guides (AMG)***

During the license renewal demonstration project phase, a need arose to study the critical components in more detail and to generate a generic AMG that could be used by other plants in their applications as well as be subjected to NRC review. The USDOE through the Sandia National Laboratory contracted for the development of ten individual AMGs, using a standard format and content guide. The ten critical components to be covered were chosen by an industry consortium and included the following reports:

- Electrical Switchgear (SAND93-7027)
- Pumps (SAND93-7045)
- Battery Chargers, Inverters & Uninterruptible Power Supplies (SAND93-7046)
- Power and Distribution Transformers (SAND93-7068)
- Motor Control Centers (SAND93-7069)
- Heat Exchangers (SAND93-7070)
- Stationary Batteries (SAND93-7071)
- Tanks and Pools (SAND96-0343)
- Electrical Cable and Terminations (SAND96-0344)
- Non-Reactor Pressure Boundary Piping (Draft) (TR-88953)

While these reports cover both, passive (Heat Exchangers, Piping, Tanks/Pools, Cable) and active components (batteries, inverters/UPS, pumps, transformers, switchgear and motor control centers) they have become a valuable industry reference for the assessment of power production equipment. The AMGs contain a comprehensive review of industry operating experience, failure data, aging management techniques, and aging management options. The Cable AMG has become the industry bible on cable degradation, cable life determination and cable aging management.

### ***EPRI Generic License Renewal Industry Reports for Major Components***

In parallel to the DOE-Sandia AMGs EPRI also produced ten License Renewal Industry Reports. The EPRI addressed issues related to both the boiling water reactors (BWR) and the pressurized water reactors (PWR).

The EPRI reports were developed with participation from the General Electric BWR and Westinghouse PWR Owners Groups. The objectives of the EPRI reports were to provide the nuclear industry with aging technical basis documents and to support the technical review of license renewal applications by the USNRC.

The long-lived passive components and structures examined in the reports included:

- BWR plant primary containment
- PWR containment structures
- Class 1 structures
- PWR reactor coolant system
- low voltage, in-containment, environmentally-qualified cable

- BWR primary coolant pressure boundary
- BWR and PWR reactor vessels
- BWR and PWR reactor vessel internals

These reports are in-depth studies of historical performance and operating experience, failures and failure history, aging effects, and aging mechanism. The reports also provided information on aging management technologies and programs and discussed the aging management options for component parts and aging mechanisms that are not currently being managed or are not accessible (such as, underground structures, embedded steel and piping, and cable in conduits).

Over the years these reports have been of significant value for both the US nuclear industry and regulator as well as for nuclear plant operators and regulators in other countries. In particular, the reports on structures and containments have formed the basis of similar aging reports developed by the International Atomic Energy Agency in Vienna.

Much of the information in the reports on Class 1 structures and cables is application to both nuclear and non-nuclear facilities.

### ***NRC Nuclear Plant Aging Research (NPAR) Program***

To compensate for and to supplement the industry research of component aging, the USNRC funded a large multimillion-dollar research program to study aging of more than 100 different topics and components. Most of the actual research was conducted by the national laboratories (Oakridge, Argonne, Pacific Northwest, Sandia, and Idaho). The USNRC managed the program and provided for the technical review of selected reports by industry experts and users. A summary report (NUREG- 1377) was generated and updated annually to maintain an overview of the program status, components and topics being studied, short briefing reports and summaries for those reports completed. The reports for the selected components included passive and active components, as well as special topics, such as fatigue, material embrittlement, monitoring for aging, maintenance issues, seismic effects, and operating experience. Most of these reports are readily available from the NRC website. A more detailed discussion of the NPAR Program can be found in the companion briefing report *Condition Monitoring of Passive Systems, Structures, and Components* (CGI Report 06:22).

### ***EPRI Generic Aging Management Tools***

As a follow-up to the earlier industry reports for critical component aging, EPRI consolidated the research conducted within those reports, other owner's group initiatives, the NRC NPAR program and the early LICENSE RENEWAL applications in a series of Aging Management Tools. The three documents provide specific guidance in matrix format (similar to the later GALL report) to license renewal applicants for the applicable aging effects, mechanisms, exposure environments, affected materials and effective aging management programs. The tools are as follows:

- *Mechanical Implementation Guideline And Mechanical Tools* – contains a number of individual reports to cover the applicable service conditions and environments for:
  - treated water conditions
  - raw water
  - oil containing systems
  - gas containing systems
  - external surfaces
  - bolting
  - heat exchangers
  - fatigue affected systems
- *License Renewal Electrical Handbook* – contains aging management guidance for electrical cable and terminations, penetrations, buses, conductors and insulators.
- *Aging Effects for Structures and Structural Components (Structural Tools)* -- contains aging management guidance for steel and concrete structures (beams, columns, floors, walls, foundations, roofs, etc), above and below grade, underwater, in freeze-thaw climate, indoors and outdoors. Also covered are piping and cable tray supports, electrical and control cabinets, racks and enclosures, fire barriers, elastomer seals and barriers, galvanized steel and threaded fasteners. An example of the aging matrix for steel components is shown on Table 10.

### ***The INPO AP-913 Equipment Reliability Program***

The Nuclear Plant Reliability Data Search (NPRDS) database was created by INPO following the Three Mile Island event to respond to NRC requests for generic operating experience accumulation and assessment. Each plant provided input of component failures and causes to facilitate searches and to identify precursors to potential failures. With the promulgation of the maintenance rule, a new software tool was required to manage the failures associated with the equipment included under the Maintenance Rule. These failures are considered "Maintenance Preventable Functional Failures" (MPFFs) and repeat failures and are reportable under the Maintenance Rule. In operation since 1996, the database now contains more than 100,000 failure events and descriptions and as such is a credible basis for establishing component failure rates. One major shortcoming is the absence of component populations, such that component estimates need to be made for the 104 operating plants. For some commodities, such as valves, breakers or cables, uncertainties are encountered. Nevertheless, the database has become a very useful tool to examine operating experience and failure modes. Another caution for the use of the data is the fact that reporting of failures is only required for systems and components included in the scope of the Maintenance Rule, that is largely safety related equipment.

**Table 10: Applicable Aging Effects for Structural Steel Components and Materials**

APPLICABLE AGING EFFECTS	CARBON STEEL	LOW-ALLOY STEEL	GALVANIZED STEEL	STAINLESS STEEL
<b>Loss of Material</b>				
General Corrosion	Y	Y	N-protected atmosphere weather Y-exposed atmosphere weather	N
Galvanic Corrosion	N	N	N	N
Crevice Corrosion	N	N	N	N
Pitting Corrosion	N	N	N	N
Erosion and Erosion Corrosion	NA	NA	NA	NA
Microbiologically Induced Corrosion	N	N	N	N
Wear	N	N	N	N
<b>Cracking</b>				
Hydrogen Damage	N	N	N	N
Stress Corrosion	N	N	N	N
Fatigue	N	N	N	N
<b>Mechanical Distortion</b>				
Creep	N	N	N	N
Fatigue	N	N	N	N
<b>Change in Material Properties</b>				
Elevated temperatures	N	N	N	N
Irradiation Embrittlement	N*	N*	N*	N*
Intermetallic Embrittlement	NA	NA	N-provided temperature < 400 °F	NA
Key: Y- aging mechanism is applicable . N- aging mechanism is not applicable NA- Not Applicable to this chapter *- Outside Primary Shield Wall				

While not a bona fide research program, this INPO developed reliability management guide provides plant owners with a structured methodology to more effectively apply and manage their maintenance programs. The guide is not mandatory and plant owners can customize their programs to incorporate existing programs and procedures, as long as the principal objective of improving equipment reliability is met. The programmatic details are discussed in an earlier section of this report.

### **NEI Guidelines**

The Nuclear Energy Institute (NEI) has accepted the responsibility of developing industry guidelines for the implementation of new regulatory requirements and other topics not addressed by EPRI or INPO, such as business planning. The three most

prominent guides associated with aging management of plant systems, structures, and components are:

- NEI-95-10, *Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule Plants* – this guide is discussed in the License Renewal Rule section of this report and in the companion briefing report CGI 06:22.
- NEI-93-01, *Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants* – this guide is discussed in the Maintenance Rule section of this report
- NEI-AP-940, *Nuclear Asset Management Process Description and Guideline*:

In NEI-AP-940 asset management process guidance includes strategic and generation planning, project evaluation and ranking, long range planning, budgeting, and plant / fleet valuation. The process deals with the high-level business management of a fleet or a single plant. The most interesting section of this guide is the topic of project evaluation and ranking. Industry surveys showed that there is no consensus with respect to the method of selecting and ranking specific projects from a multiple projects listing and being restrained by a fixed budget. Many different methods have been proposed, from risk ranking, expert panel (Delphi), cost-benefit, operational priorities, safety considerations and the rucksack method (what to take with you in a fixed volume rucksack for a one week survival trip).

### ***Ongoing EPRI Aging Research***

A lesson learned about aging management, is that no matter how precise and detailed the aging studies are performed, there is always the unexpected, often a combination of events that surprises the engineers. In the nuclear industry there is no exception and unknown material behavior, degradation mechanisms and aging effects are discovered as the plants age. Largely due to the inspection programs in place today, these “surprises” are discovered in time to facilitate timely corrective actions.

During the last ten years, accelerated degradation associated with crack initiation was discovered in the stainless steel reactor vessel internals. The cause was determined to be stress corrosion cracking, assisted by fatigue and un-annealed weldments. A major research project was initiated by the industry and managed by EPRI to find solutions, mitigation techniques and new inspection methods to investigate, size, and analyze the cracks. Just recently another new issue emerged concerning the cracking of Alloy 600 and similar Inconel alloys. This also is attributed to stress corrosion cracking, aggravated by the unique water environment (high hydrogen levels and borated water) in the PWR reactors. As before, the industry convened a large task force to deal with the issue and EPRI again is managing the project for the plant owners. These two projects and others are now combined under the EPRI Materials Research Program (MRP).

### ***Code and Standards Perspective of Aging Management***

In principle, Codes and Standards are voluntary, unless mandated by a government authority. The ASME Boiler and Pressure Vessel Code (ASME-BPVC) is mandated by the state authorities and the NRC for safety related pressure vessels, while the Electrical

Code (IEEE) and Fire Protection Codes are enforced by national building codes (NFPA). The American Concrete Institute Codes are mandated by the building codes for residential and commercial construction, however for power plants and other industrial facilities the Engineer/Designer is responsible for Code compliance. For the safety related portion of the nuclear plant, the USNRC mandates certain ACI Codes, including ACI-349. A brief description of the code activities involving aging management is presented below.

#### **ASME-BPVC PLEX Working Group**

Section XI, "Inservice Inspection of Nuclear Power Plant Components" of the ASME Boiler Code is the applicable Code specifying inspection and testing requirements for the nuclear plant components, as well as frequency of inspections, personnel qualifications and inspection techniques to be applied. A special working group was established within Section XI to accommodate the eventual integration of aging management into the Code. As a first action, the committee removed the 40-year inspection schedule (four 10-year cycles) from the Code to permit continued 10-year intervals until the plant shuts down for decommissioning. In the interim the Working Group monitors technical issues as they emerge from the license renewal process for future integration. The Code does not react to new issues very quickly and purposely takes its time to test implementation problems before codifying them.

#### **IEEE Working Group for Aging Management of Electrical and I&C Equipment**

The Institute of Electrical and Electronics Engineers (IEEE) generated a guide for aging management of electrical and instrumentation equipment, P-1205 (draft), "IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class IE Equipment Used in Nuclear Power Generating Stations". The guide contains a comprehensive aging effects and mechanisms matrix and the associated effective aging management methods. It is not certain if this guide was ever formally issued.

#### **ACI Standards for Evaluation of Existing Concrete Structures**

The American Concrete Institute (ACI) had a working condition survey standard for concrete inservice since 1968, ACI-201.1R, "Guide for Making a Condition Survey of Concrete Inservice". The Code addresses some 38 degradation effects, including ten types of cracking. For most of the degradation effects, reference photographs are provided for the inspector to discern the exact nature of the defects. The code has been updated a number of times, the 1996 version being the latest. The code has been widely in use for municipal and public use structures (garages, bridges, event buildings, etc), but has also been applied to power plants, including the nuclear facilities.

More recently, ACI issued a new Code with specific application to safety related structures, ACI-349-3R, "Evaluation of Existing Nuclear Safety Related Concrete Structures". In addition to the condition survey requirements as defined in ACI-201, this standard provides definitive acceptance criteria at two levels, Acceptance without further evaluation and acceptance with review. The acceptance criteria for concrete inspections are provided in Table 11.

**Table 11: Concrete Inspection Acceptance Criteria (from ACI-349), Edited**

Concrete Defect Description	Acceptance Criteria Without Review	Acceptance Criteria With Review
Leaching and Chemical Attack	None permitted	None permitted
Abrasion, Corrosion, Cavitation	None permitted	Evaluate Defects
Drummy Areas, Poor Concrete	None permitted	<Cover Concrete
Popouts, Voids	<20mm diameter or Equiv. Area	<50mm diameter or Equiv. Area
Scaling	<5mm in depth	<30mm in depth
Spalling	<10mm in depth, <100mm in any dimension	<20mm in depth, <200mm in any dimension
Passive Cracks	<0.4mm in width	<1.0mm in width
Passive Deflection, Settlement	None permitted	Within design limits
Loss of Coatings	<4000mm <sup>2</sup> for any area	>4000mm <sup>2</sup> for any area
Leakage	None permitted	Evaluate any leakage



## **Lessons Learned from the Initial License Renewals**

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The license renewal process has been a 25-year learning curve. The initial version of the Rule in 1991 was found to be open-ended with an overwhelming program scope. The nuclear industry and the USNRC staff identified many problems with the initial Rule. The amended Rule in 1995 established a regulatory process that is simpler, more stable, and more predictable than the initial License Renewal Rule. It put the focus of the license renewal assessment on the licensees aging management activities concerning passive and long-lived SSCs. It also clarified the focus on managing the adverse effects of aging rather than identification of all aging mechanisms. The changes to the integrated plant assessment (IPA) process were to make it simpler and more consistent with the revised focus on passive, long-lived systems; structures and components. However there remained a number of areas where further improvements were needed in the application process.

In the late 1990's the Calvert Cliffs plant announced its plan to file an application using the revised Rule and the NEI license renewal application guide, NEI 95-10. NEI 95-10 provides an approach that the USNRC has found to be acceptable and has endorsed for implementing the requirements of the License Renewal Rule. The guidelines in the NEI 95-10 report are based on industry experience in implementing License Renewal Rule.

The review of the Calvert Cliffs applications by the USNRC staff revealed some serious problems. These included the fact the staff had very little guidance, no training, and a diverse view of what the regulations actually meant. Also, questions were raised with respect to the license renewal application costs, utility commitment, and effectiveness of the Rule. Senior management from both the USNRC and the nuclear industry worked to address these and other weaknesses with the license renewal process. This involved numerous site visits to familiarize the USNRC staff with site conditions and to conduct scope audits.

It became apparent that much of the information to be developed for an application is of a generic nature. It was determined that standards and guidance were needed to avoid unnecessary duplication of work. Guidance was also needed to avoid technical inconsistencies so that there are not different interpretations of the technical findings and conclusions from one application reviewer to another.

To address these and other issues the USNRC and the nuclear industry developed a number of guidance documents. One of the key documents has been the Generic Aging Lessons Learned (GALL) Report (NUREG-1801). The GALL report provides a template of aging management programs that have been determined to be acceptable by the USNRC to manage the aging effects of safety critical passive and long-lived SSCs. The GALL Report documents the USNRC's basis for determining which existing programs are adequate without modification and which existing programs should be augmented for license renewal. A complimentary Standard Review Plan (NUREG-1800) was developed as a guide to the USNRC staff for their review of the application information.

Strong emphasis has been placed on training NRC staff and plant owners to assure that all stakeholders are aware of the process, requirements, tools and reference guides. The NRC implemented an extensive training program for their staff members and assigned additional inexperienced staff to their site audit teams to observe and learn the process. Training modules also were developed by the owners groups and EPRI to be conducted at the plant sites for different levels of staff, management briefings and working level indoctrinations.

The next license renewal applicants were able to use these guidance documents in the development of their applications. Major cost reductions were realized with the streamlined process. Savings were estimated to be in the range of 50% to 75% with respect to the Calvert Cliffs project costs. Further improvements were initiated by the USNRC to shorten the review process from three years to less than two years, to deal with staff shortages and reflect the learning curve. The nuclear industry and NEI also sponsored development of the Aging Management Tools, a commitment database (to assure that applicants do not over-commit or fail to address previous USNRC issues), and a searchable database for NRC generic communications.

The lessons learned from these efforts and the continued review process has been incorporated into the latest revision of the GALL report and the Standard Review Plan. The process has matured to a point where the USNRC has been able to review multiple plant applications in parallel. Utilities have seen major cost and schedule reductions for the license renewal process; fewer site visits and experienced significantly less interaction with the USNRC during the review process.

Some of the key documents that are used by both the licensees and the USNRC during the license renewal process are listed in Table 12. These are all "living documents". Revised versions of the reports are routinely produced that incorporate changes based on experience gained from numerous license renewal application reviews by USNRC staff and from insights identified by the industry. For example, the NEI 95-10 is currently in its sixth revision.

**Table 12: License Renewal Support and Guidance Documents**

Document Title	Document Identifier
Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants	NUREG-1800 (USNRC)
Generic Aging Lessons Learned (GALL) Report	NUREG-1801 (USNRC)
Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses	Regulatory Guide 1.188 (USNRC)
License Renewal Inspections	Inspection Manual 71002 (USNRC)
Policy and Guidance for License Renewal Inspection Programs	MC-2516 (USNRC)
Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule	NEI 95-10 (Nuclear Energy Institute)

## Reaching Process Consensus among Stakeholders

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As described above, the license renewal process has undergone substantial evolution. This implies recognition of the need to and willingness to change by all parties involved. Pressure was applied on the regulator to keep the process on track, simplify it and make it effective for all stakeholders. The mistakes made with the initial rule could not be repeated and a stable and workable process had become essential for success. Such a proven process also lends itself to standardization, further assuring consistency and efficiency. One of the key concerns with new regulations is the threat of "Rule Creep", that is the ever-changing interpretations of the regulations, issuance of new guidance, raising of new issues, different treatment of the same issue for other applicants and the constant desire to invent new wheels. In this case, the NRC and utilities were jointly motivated to develop a streamlined and stable methodology. The development of the GALL report and NEI license renewal Guide, NEI 95-10, are considered major tools to achieve those objectives.

The process has by no means found its end point, additional lessons learned, improvements and experience feedback are being monitored and revisions of the key references are planned to capture process changes. The most recent evidence of the continuing consensus evolution is an EPRI project to prepare so-called "Road Maps" for generic technical issues and associated aging management programs. This project evolved from the tallying and review of individual plant commitments and to sort those that are common to many plants and therefore deserve identical treatment and resolution. These road maps are to assist plant owners to develop implementation tasks for their license renewal commitments at least costs and assuring acceptability of implementation. The road maps also identify technical issues that are not fully resolved yet and require research to facilitate task implementation prior to the start of the license renewal period. The NRC is expected to audit these implementation activities in the future and they are tracking compliance with the applicant's commitments.

Another method to communicate current development, lessons learned and ideas of process improvement is facilitated through frequent workshops sponsored by the NRC and the industry. These workshops encourage presentations from all stakeholders and the public to solicit input and opinions. They are also a vehicle to share information with management, vendors, suppliers of services, inspectors, public members and other interested parties. All or most of the license renewal information, including the complete application packages, USNRC application reviews (SER), rules and regulations and guidance documents (GALL, SRP-LR, NEI-95-10, Regulatory Guides, Interim Staff Guidance) are available on the USNRC website ([www.nrc.gov](http://www.nrc.gov)).

## Life Extension Implementation at the Plants

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### *The Two-Step Process*

Life Extension for a plant is considered a two-step process. The initial step is to secure regulatory approval through license renewal application process. The second step is to actually implement life extension for the plant. Although the approval of a license renewal allows continued operation for 20-years it does not require such operation. The decision to actually operate beyond the current license period is up to the licensee. It is dependent on such factors as power generation planning, economic justification, and prevailing condition of the plant.

The aging management requirements of the license renewal application only apply to the safety-related scope under the License Renewal Rule – about one-third of the plant equipment. In order to prepare the plant for life extension, the remaining power production part of the plant has to be upgraded and evaluated to assure that the equipment can support reliable operation for an extra 20 years. Many plants will wait until about five years before the extended license becomes effective (at year 35 of the plant life) to avoid large capital investments that may become stranded if the plant owners decide not to implement life extension. Often these objectives are compromised, because the plant may need a new turbine generator or main transformer at year 34, without life extension such an investment would not be cost beneficial such that the extended life period is needed in the cost benefit analysis.

### *Proactive Implementation Tasks*

While most of the license renewal commitments for the plant apply only for the extended operating period, there are a number of preparatory and mitigative actions taken by the plants to reduce future costs and to collect the information needed for future assessments. The following are some of the proactive, diagnostic, preventive, predictive and investigative activities performed by plants in preparation for license renewal:

- Temperature Survey of Spaces for EQ
  - Initial survey with Pyrometer or Thermography to locate “Hot Spots”, actual temperature variations within the space, room or enclosure, locations with temporary elevated temperature and containing vulnerable electrical equipment
- Fatigue Cycle Counting and Monitoring
  - Simple cycle counting and transient categorization to be compared to the design basis assumptions and projected for 60 years. Thermal transient monitoring to determine the rate of transients for future reclassification and margin hunting.
- Biological Essays (Tests) of Water Sources
  - Sampling and testing for MIC of all water sources (Service Water, raw water, demineralized water, closed loops, sumps, storage tanks, lube oil, fuel oil)

- Visual Inspection of Inaccessible Areas
  - When opening up equipment (pumps, valves, heat exchangers, tanks/vessels) or removing insulation, perform a visual (VT-1 or VT-3) inspection of the normally inaccessible surfaces and record the conditions (corrosion, cracking, loss of material, staining, etc). When excavating buried/embedded pipe, steel and concrete structures, trenches, cable ducts, perform a VT-1 or VT-3 and take good pictures of the normally inaccessible surfaces.
- Wall Thickness Measurements
  - When possible, conduct sample UT wall thickness measurements on carbon steel piping, valve bodies, pump casings, heat exchanger and vessel shells, tank walls and bottoms, etc. Identify and record abnormal conditions.
- Underwater Inspections
  - When using divers in the intake, fuel pools, etc, train divers for VT-1 examinations and debrief afterwards. Document conditions and take photos if possible.
- Soil and Groundwater Tests
  - Take soil and groundwater samples and test for chlorides, sulfates, silica, cement paste, iron oxides. Take samples as near to the structure as possible from test wells, borings, and excavations. Monitor groundwater level and variations at least over a few years.
- Settlement Monitoring
  - If the plant sits on soil or piles, consider installing, reactivating or updating the settlement monitoring system for the principal structures (Containment, Auxiliary or Reactor Building, Intake).
- Air Sampling and Testing
  - Sample and test the external plant air to determine the extent and type of air pollution at the site, measure chlorides, CO, SOX, NOX, particulates to establish aggressiveness. For ocean plants, measure the concentration of NaCl (salt) for various weather and wind conditions in the ventilation intakes.
- Beltline Material Surveillance
  - Review the material test coupon withdrawal schedule and make adjustments as early as possible to accommodate a 60-year (and possibly 80 year) operating period. Consider reinsertion of the material, using miniaturization and reconstitution of the coupons for future embrittlement tests.

### ***License Renewal Commitment Implementation after Year 40***

Once the plant approaches the end of the current operating license and decided that economics dictate continuation of operation and that an extended life is warranted and desirable, the commitments made in the license renewal application become mandatory and full implementation must be achieved before the plant can continue to operate past

40 years. Plants consider it unwise to wait to the last minute, particularly for new inspection programs, such as certain one-time inspections, where surprises could occur in that unexpected degradation is found. In such case, the aging management program for the affected components would not be effective and would require changes and regulatory review prior to continued operation. Other programs that merely require procedure changes or administrative actions could be delayed to the last year. Another aspect of the implementation process is to consider the generic guidance developed by NEI and EPRI, such as the "Road Maps" discussed earlier. It is important to implement tasks that are acceptable to the regulator, feature the attributes and requirements as well as scope committed to in the application.

Typically a plant will have between 200 and 400 individual license renewal tasks to implement. To assure that the tasks are all properly scheduled for completion and documentation is generated, a computerized database is normally used to track responsibility, schedule, completion status and associated design and quality assurance records/references. Many tasks require follow-up actions or re-inspections at a predetermined interval and inspection results must be evaluated and documented. The plant has to be able to verify implementation to the regulator's onsite inspectors.

A new Appendix to the License Renewal Guide, NEI 95-10, has been drafted and issued. The purpose of this Appendix is to provide guidance to utility personnel for the follow-up actions after receipt of a renewed license.

In parallel, the USNRC has also developed inspection guidance for their onsite inspectors, as well as training programs to get ready for the extended operating period. The applicable inspection program policy document is embodied in the USNRC's "Policy and Guidance for License Renewal Inspection Programs", MC-2516. Because of its relevance an edited copy of this policy document has been included in Appendix E.

## International Applications and Interaction

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The US has taken an active role in transferring the aging management and life extension technology to other countries and international organizations. This has taken place at all levels, starting with the NRC participation in IAEA working groups to draft international standards, to individual consultants assisting foreign countries and organizations to develop their own programs. Many international conferences on nuclear technology, such as ICONE, SMIRT and IPLEX, have carried specific sessions to address life extension, aging management and operational issues. US corporations and government agencies have extensively participated in these sessions and shared their experiences and processes with the international community. Additionally, the USNRC website provides most of the regulatory guidance documents and licensing proceedings without restrictions. The following specific examples of technology transfer provide just a small piece of the word wide application of this US technology.

- The Spanish regulator required the Spanish utilities to implement the Maintenance Rule as defined in the US regulations. Assistance was provided to the utilities in shaping a program tailored to their needs and unique circumstances. Spanish regulatory representatives cross trained with the USNRC in their Washington headquarters to learn about the implementation process and the procedures.
- The IAEA relied on US participation to draft License Renewal and Aging Management standards, using US precedents, methodology and references. This has led to the development of international policy documents and generation of a number of Aging Management Standards (Containment, Reactor Vessel)
- Japan having some of the oldest nuclear plants in the world, has benefited from the early aging studies conducted in the US. Aging analysis reports have been made available to Japanese utilities through a number of technology exchange channels.
- South Korea has applied US life extension technology to their plants, both in the aging evaluations and degradation assessments/inspections.
- France (EDF) through a technology exchange agreement with EPRI has acquired the US life extension technology and life cycle management processes. A number of training seminars and workshops were held in France to present the technology.
- Switzerland, through their utility owners group, has made use of the life extension and aging management technology, specifically the identification of applicable aging effects and mechanisms and their aging management programs. Following a successful national referendum on the continuation of nuclear power, the Swiss plants are preparing their license renewal applications.

## **Lessons Learned – Possible Petroleum Industry Application**

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For over fifteen years the USNRC and the nuclear industry have been continuously refining both the license renewal requirements and the renewal process. There are many aspects of these aging management and life extension efforts and the lessons that have been learned that can be of potential value to the PSA and the Norwegian petroleum industry.

### ***Aging Research Information***

The wealth of aging related information produced by the NPAR and industry aging research programs remains a useful resource for both nuclear and non-nuclear organizations. Although the aging studies examined SSCs with respect to their operation in the nuclear plants, much of the aging degradation and aging management information is applicable to the petroleum and other industrial sectors.

### ***Continuous Improvement***

Over the years both the USNRC and the industry have been working to make the license renewal requirements and the renewal process more efficient and effective. For example, the initial version of the Rule did not provide a predictable nor stable process – it was too open ended with too broad a scope. It was determined that many aging effects were already adequately addressed during the initial operating license period. Also, the initial Rule did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which help manage plant aging phenomena as part of the on-going maintenance program tasks.

The resulting revised Rule established a simpler, more stable, and more predictable regulatory process. The key changes that were made included:

- focusing on the adverse effects of aging rather than identification of all aging mechanisms – identification of individual aging mechanisms is not required
- simplifying the integrated plant assessment process and making it consistent with the revised focus on the detrimental effects of aging
- adding an evaluation of time-limited aging analyses (TLAA)
- requiring only passive, long-lived structures and components to be subject to an aging management review for license renewal – removing active SSCs from license renewal

### ***Passive versus Active SSCs***

An important aspect of the US nuclear plant life extension requirements is the distinction between passive and active systems, structures, and components. Passive SSCs are those that do not move to function (such as, structures, heat exchangers, cables, valve and pump bodies, and piping). Their age related degradation can only be monitored and trended by performing periodic condition assessments (such as inspections, testing, and measurements).



By focusing the license renewal process on safety critical passive and long-lived components the process has been reduced to a manageable proportions – licensees are not required to consider all SSCs in order to justify extended operations.

### ***Guidance and Training***

One of the key lessons has been the need to provide clear guidance and support to all involved parties. Both the USNRC and the industry have developed guidance documents to assist in the development of aging management programs, the preparation of the renewal application, and the review of the application. As lessons are learned these guidance documents are revised to capture new insights or address emerging issues. Along with the guidance documents, training programs and support activities have greatly reduced the time and expense in preparing, reviewing, and approving the license renewal applications. The training must be supplemented with guides, pilot studies, working examples, and procedures to assure consistency of application.

### ***Integration of Aging Management Program Requirements***

From the description of the many diverse aging management programs it becomes clear that plants have a difficult time to integrate all the different requirements and to avoid duplication and non-effective maintenance tasks. Too much maintenance can lead to reliability and availability concerns and it is necessary to strive for an adequate balance. Other drivers are manpower, costs, prioritization of activities and consolidation of tasks. As part of the Maintenance Rule, the plants already have established a 13-week schedule, that is each system or train (where systems have redundant trains) will be taken out of service for one week every 13 weeks, or four times a year. During this one-week system outage, all the preventive and corrective maintenance tasks are to be completed, including invasive inspections, tests, calibrations, repairs and replacements. Once license renewal activities begin, additional tasks will have to be squeezed into the maintenance week, likely at the expense of other similar tasks.

### ***Long-term Maintenance Strategy***

When contemplating aging management for a facility, the useful life expectancy and associated planning horizon must be established first, to provide a basis for the long-term maintenance strategy. The ultimate operating life has a profound impact on the selection of appropriate and economic maintenance alternatives. It is prudent to link asset management to maintenance strategy with an objective to preserve the assets as long as economically feasible. A lesson learned from the aging management projects is that most components can be replaced and that good aging management can preserve structures for decades if not centuries (the B-52 aircraft are over 50 years old and are still flying).

### ***Reducing Component Failures***

No other maintenance action taken in the plant will have as much impact on equipment reliability and plant availability as reducing the failure rates of components. The plant or system performance cannot be better than the worst performing critical component. All efforts must therefore be directed to identify incipient failures, precursors and age related degradation. This implies that inspections and diagnostics must be employed in

areas where failure knowledge and prediction is inadequate. In general plants are not aggressive enough to reduce failures and to invest in predictive maintenance. Even though some plants have a "Zero Failure Tolerance" policy, when it comes to making investments, replacements are preferred.

### ***Effectiveness of Condition Monitoring***

It is not unusual to find that plants have implemented predictive maintenance tools to monitor equipment conditions, but the diagnostics are not effective in preventing failures. One example is vibration monitoring of rotating equipment, when data is read infrequently (once a month) with portable equipment. Bearing degradation can progress, and often will, from minor imbalance to catastrophic failure within minutes or hours. Continuous monitoring with alert and warning levels is significantly more effective. Another example is oil analysis and ferrography performed at certain intervals is mostly used to justify an increase in the oil change interval. Installing oil reservoir breather caps and filters will be more effective to keep contaminants out of the oil. Thermography has slowly made inroads in detecting degradation and incipient failures, even though the surveys are done typically only annually and only for readily accessible equipment. More aggressive and effective thermography can be performed for electrical equipment inside enclosures, using infrared windows. Enclosed motors also can be surveyed internally using infrared windows on the casing to measure rotor and stator, slip ring and bearing temperatures to identify hot spots.

### ***Establishing Appropriate Inspection Procedures***

The two major questions concerning an effective inspection program are: What and how often to inspect? For components such as cable, piping, valves, pumps, motors a sampling program is the most effective means of inspection. Sampling rates must be representative with respect to component size, vendor, materials, service and environmental exposure. An example is to start with a 10% sampling rate and decreasing the rate after five years if nothing is found. Or doubling the rate if defective equipment is found. If more than one deficiency is found, a 100% inspection would be justified.

If a risk analysis is available, component selection and prioritization can be made by using risk measures. If aging evaluations have been performed, the most vulnerable components and locations should be known and become the focus of inspections. The frequency of inspections depends on the degradation one is looking for. If the known degradation is a fairly rapid and aggressive process, inspection periods of one to two years are not uncommon, while inspections of steel and concrete structures are undertaken at ten-year intervals. If acceptable defects are found or if repairs have been performed, the inspection periods should be shortened, commensurate with the rate of degradation or on an annual basis.

Just because nothing has been found for 20 or 30 years does not imply that degradation is absent, it may just be slow or takes a long time to crack initiation and propagation. The most troubling degradation issues in the nuclear plants became apparent after more 20 years of operation and exposure.

### ***Aging Management of Inaccessible Equipment***

A major concern in the license renewal process is equipment that is not readily accessible to inspection, testing or diagnostics. Underground piping and cable, embedded steel, underwater structures are examples of these cases. Unique programs were developed to deal with these components and to assure that degradation is adequately managed. Onetime inspections, selected excavations, use of test coupons and monitoring of the service environment (soil and water chemistry, evidence of corrosion products) were employed to indicate when and where degradation becomes active. Managing these inaccessible components and structures should be a priority, because replacement and repair is not usually a feasible option.

### ***Sharing Experiences***

An effective failure reduction strategy is to access, review and analyze equipment failures at other facilities. Problems and difficulties at older facilities or those that have greater operating hours can be a valuable source of leading indicators of what to watch out for. Generic failures may point out particularly vulnerable parts, impact of abnormal operation, failure indicators, methods of detection and actual service hours to failure.

Another important source of information is gained by monitoring of other plant's experience and programs to identify those activities that work and those that do not work. The sharing of best practices, however has been impeded by the deregulation of the nuclear power industry. Unfortunately, in certain cases, information that provides an economic advantage to one plant becomes a valuable commodity that is likely not to be shared with others.

Manufacturers usually do not have a good understanding of the operational performance of their equipment in the field and are only performing root cause assessments when they receive a warranty claim. Maintenance recommendations from the manufacturer must be taken with great caution and only if a technical basis exists for their recommendations, such as operational failure rate trends and component life expectancies.

### ***Pilot Projects***

When attempting to create new regulations with complex processes, it is imperative to test the regulations and processes in a real application environment. The first License Renewal rule failed as a result of applying it to a demonstration project. All stakeholders must participate in this test program to understand the implications and be willing to search for acceptable compromise. The revised rule was a success because of frequent interaction among the stakeholders, participation of and guidance from senior management representatives and a willingness to change and adapt during the development process.

### ***Properly Quantify Consequential Failure Costs***

Often when cost benefit analyses are performed to justify corrective or preventive actions following equipment failures, the consequential failure costs are not adequately incorporated into the analyses. This can lead to erroneous assumptions and conclusions.

Failure costs can include lost production, personnel injury, lost work time, and medical costs. The more serious the failure the greater the impact on the plant and the organization. Some plants have been forced to shutdown for several years because of equipment failures and human errors. It is therefore important to identify and quantify the consequential failure costs to support reliable conclusions and to justify implementation of a predictive maintenance and effective aging management strategy.

### ***Quantify Consequential Failure Costs***

Often when cost benefit analyses are performed to justify corrective or preventive actions following equipment failures, the consequential failure costs are not adequately incorporate into the analyses. This can lead to erroneous assumptions and conclusions. As stated earlier, the value of one day's lost power production approaches one Million. Dollars for most plants. In addition, some failures cause personnel injury, lost work time, medical costs and inquiries by the safety authorities. Other failure consequences may even be more drastic, including fires, flooding, steam escape, explosions, radioactive contamination or releases. The more serious the failure, the more impact there will be on the corporate well being, from an impact on the stock price, annual dividend and earnings, public image and potential regulatory actions and fines. Some plants have been forced to shutdown for periods up to two years, because of equipment failures and human errors. It is therefore important to identify and quantify the consequential failure costs to support reliable conclusions and to justify implementation of a predictive maintenance and effective aging management strategy.

### ***Conclusions***

The aging management and life extension process for the US nuclear industry has been refined and improved over the years. It has become an efficient and effective method to ensure that the nuclear plants in the United States can be safely operated beyond their original 40-year operating license. By dividing the safety critical systems, structures, and components into passive and active categories the industry and regulator have reduced the potentially overwhelming analysis effort to a reasonable and manageable size.

By working together, the nuclear industry and the US Nuclear Regulatory Commission (USNRC) have been able to technically justify life extension. The process has been structured to not be an economic or resource burden on either the licensees or the USNRC. However, all parties are continually reviewing the process and results to identify where improvements can be made.

The process has been selected as a viable method by many international regulatory and nuclear industry organizations, including those in Spain, Taiwan, and Korea. The International Atomic Energy Agency in Vienna has also adopted the process as the model for ensuring safe extended life operations.

The aging management and life extension process can be easily adapted to other industries. The development strategy, research material, specific elements of the process, and many of the lessons learned can all be of potential value to the PSA and Norwegian petroleum industry in ensuring safe extended operations of the facilities.

## Appendices

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- A The Maintenance Rule: Title 10 of the US Code of Federal Regulations, Part 50.65 (10 CFR 54.65)
- B The License Renewal Rule: Title 10 of the US Code of Federal Regulations, Part 54 (10 CFR Part 54)
- C USNRC Guidance Concerning Aging Effects and Aging Mechanisms
- D Aging Management Program Example – Concrete Structures Monitoring: GALL Report-(NUREG-1801 Vol 2)
- E License Renewal Inspection Policy and Guidance: USNRC Inspection Manual Chapter (MC) 2516 – Policy and Guidance for the License Renewal Inspection Programs
- F Nuclear Related Aging Management and Life Extension Abbreviations and Acronyms
- G Bibliography of Selected Nuclear Aging Management and Life Extension Reports

# Appendix A

## The Maintenance Rule

### Title 10 of the US Code of Federal Regulations, Part 50.65 (10 CFR 54.65)

#### Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants

The requirements of this section are applicable during all conditions of plant operation, including normal shutdown operations.

(a)(1) Each holder of a license to operate a nuclear power plant under Secs. 50.21(b) or 50.22 shall monitor the performance or condition of structures, systems, or components, against licensee-established goals, in a manner sufficient to provide reasonable assurance that such structures, systems, and components, as defined in paragraph (b), are capable of fulfilling their intended functions. Such goals shall be established commensurate with safety and, where practical, take into account industry-wide operating experience. When the performance or condition of a structure, system, or component does not meet established goals, appropriate corrective action shall be taken. For a nuclear power plant for which the licensee has submitted the certifications specified in Sec. 50.82(a)(1), this section only shall apply to the extent that the licensee shall monitor the performance or condition of all structures, systems, or components associated with the storage, control, and maintenance of spent fuel in a safe condition, in a manner sufficient to provide reasonable assurance that such structures, systems, and components are capable of fulfilling their intended functions.

(2) Monitoring as specified in paragraph (a)(1) of this section is not required where it has been demonstrated that the performance or condition of a structure, system, or component is being effectively controlled through the performance of appropriate preventive maintenance, such that the structure, system, or component remains capable of performing its intended function.

(3) Performance and condition monitoring activities and associated goals and preventive maintenance activities shall be evaluated at least every refueling cycle provided the interval between evaluations does not exceed 24 months. The evaluations shall take into account, where practical, industry-wide operating experience. Adjustments shall be made where necessary to ensure that the objective of preventing failures of structures, systems, and components through maintenance is appropriately balanced against the objective of minimizing unavailability of structures, systems, and components due to monitoring or preventive maintenance.

(4) Before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. The scope of the assessment may be limited to structures, systems, and components that a risk-informed evaluation process has shown to be significant to public health and safety.

(b) The scope of the monitoring program specified in paragraph (a)(1) of this section shall include safety related and nonsafety related structures, systems, and components, as follows:

(1) Safety-related structures, systems and components that are relied upon to remain functional during and following design basis events to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, or the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in Sec. 50.34(a)(1), Sec. 50.67(b)(2), or Sec. 100.11 of this chapter, as applicable.

(2) Nonsafety related structures, systems, or components:

(i) That are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures (EOPs); or

(ii) Whose failure could prevent safety-related structures, systems, and components from fulfilling their safety-related function; or

(iii) Whose failure could cause a reactor scram or actuation of a safety-related system.

(c) The requirements of this section shall be implemented by each licensee no later than July 10, 1996.

# Appendix B

## The License Renewal Rule

### Title 10 of the US Code of Federal Regulations, Part 54 (10 CFR Part 54)

#### Requirements for Renewal of Operating Licenses for Nuclear Power Plants

54.1 Purpose.	54.22 Contents of application—technical specifications.
54.3 Definitions.	54.23 Contents of application—environmental information.
54.4 Scope.	54.25 Report of the Advisory Committee on Reactor Safeguards.
54.5 Interpretations.	54.27 Hearings.
54.7 Written communications.	54.29 Standards for issuance of a renewed license.
54.9 Information collection requirements: OMB approval.	54.30 Matters not subject to a renewal review.
54.11 Public inspection of applications.	54.31 Issuance of a renewed license.
54.13 Completeness and accuracy of information.	54.33 Continuation of CLB and conditions of renewed license.
54.15 Specific exemptions.	54.35 Requirements during term of renewed license.
54.17 Filing of application.	54.37 Additional records and recordkeeping requirements.
54.19 Contents of application—general information.	54.41 Violations.
54.21 Contents of application—technical information.	54.43 Criminal penalties.

#### General Provisions

##### § 54.1 Purpose.

This part governs the issuance of renewed operating licenses for nuclear power plants licensed pursuant to Sections 103 or 104b of the Atomic Energy Act of 1954, as amended (68 Stat. 919), and Title II of the Energy Reorganization Act of 1974 (88 Stat. 1242).

##### § 54.3 Definitions.

(a) As used in this part,

*Current licensing basis* (CLB) is the set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent final safety analysis report (FSAR) as required by 10 CFR 50.71 and the licensee's commitments remaining in effect that were made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports.

*Integrated plant assessment* (IPA) is a licensee assessment that demonstrates that a nuclear power plant facility's structures and components requiring aging management review in accordance with § 54.21(a) for license renewal have been identified and that the effects of aging on the functionality of such structures and components will be managed to maintain the CLB such that there is an acceptable level of safety during the period of extended operation.

*Nuclear power plant* means a nuclear power facility of a type described in 10 CFR 50.21(b) or 50.22.

*Time-limited aging analyses*, for the purposes of this part, are those licensee calculations and analyses that:

- (1) Involve systems, structures, and components within the scope of license renewal, as delineated in § 54.4(a);
- (2) consider the effects of aging;
- (3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;
- (4) Were determined to be relevant by the licensee in making a safety determination;
- (5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in § 54.4(b); and

- (6) Are contained or incorporated by reference in the CLB.

(b) All other terms in this part have the same meanings as set out in 10 CFR 50.2 or Section 11 of the Atomic Energy Act, as applicable.

#### **§ 54.4 Scope.**

- (a) Plant systems, structures, and components within the scope of this part are--
- (1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions--
    - (i) The integrity of the reactor coolant pressure boundary;
    - (ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or
    - (iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable.
  - (2) All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section.
  - (3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

- (b) The intended functions that these systems, structures, and components must be shown to fulfill in § 54.21 are those functions that are the bases for including them within the scope of license renewal as specified in paragraphs (a)(1) - (3) of this section.

[60 FR 22491, May 8, 1995, as amended at 61 FR 65175, Dec. 11, 1996; 64 FR 72002, Dec. 23, 1999]

#### **§ 54.5 Interpretations.**

Except as specifically authorized by the Commission in writing, no interpretation of the meaning of the regulations in this part by any officer or employee of the Commission other than a written interpretation by the General Counsel will be recognized to be binding upon the Commission.

#### **§ 54.7 written communications.**

All applications, correspondence, reports, and other written communications shall be filed in accordance with applicable portions of 10 CFR 50.4.

#### **§ 54.9 Information collection requirements: OMB approval.**

(a) The Nuclear Regulatory Commission has submitted the information collection requirements contained in this part to the Office of Management and Budget (OMB) for approval as required by the Paperwork Reduction Act (44 U.S.C. 3501 et seq.). The NRC may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. OMB has approved the information collection requirements contained in this part under control number 3150-0155.

(b) The approved information requirements contained in this part appear in §§ 54.13, 54.15, 54.17, 54.19, 54.21, 54.22, 54.23, 54.33, and 54.37.

[60 FR 22491, May 8, 1995, as amended at 62 FR 52188, Oct. 6, 1997; 67 FR 67100, Nov. 4, 2002]

#### **§ 54.11 Public inspection of applications.**

Applications and documents submitted to the Commission in connection with renewal applications may be made available for public inspection in accordance with the provisions of the regulations contained in 10 CFR Part 2.

#### **§ 54.13 Completeness and accuracy of information.**

(a) Information provided to the Commission by an applicant for a renewed license or information required by statute or by the Commission's regulations, orders, or license conditions to be maintained by the applicant must be complete and accurate in all material respects.

(b) Each applicant shall notify the Commission of information identified by the applicant as having, for the regulated activity, a significant implication for public health and safety or common defense and security. An applicant violates this paragraph only if the applicant fails to notify the Commission of information that the applicant has identified as having a significant implication for public health and safety or common defense and security. Notification must be provided to the Administrator of the appropriate regional office within 2 working days of identifying the information. This requirement is not applicable to information that is already required to be provided to the Commission by other reporting or updating requirements.



#### **§ 54.15 Specific exemptions.**

Exemptions from the requirements of this part may be granted by the Commission in accordance with 10 CFR 50.12.

#### **§ 54.17 Filing of application.**

- (a) The filing of an application for a renewed license must be in accordance with Subpart A of 10 CFR Part 2 and 10 CFR 50.4 and 50.30.
- (b) Any person who is a citizen, national, or agent of a foreign country, or any corporation, or other entity which the Commission knows or has reason to know is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government, is ineligible to apply for and obtain a renewed license.
- (c) An application for a renewed license may not be submitted to the Commission earlier than 20 years before the expiration of the operating license currently in effect.
- (d) An applicant may combine an application for a renewed license with applications for other kinds of licenses.
- (e) An application may incorporate by reference information contained in previous applications for licenses or license amendments, statements, correspondence, or reports filed with the Commission, provided that the references are clear and specific.
- (f) If the application contains Restricted Data or other defense information, it must be prepared in such a manner that all Restricted Data and other defense information are separated from unclassified information in accordance with 10 CFR 50.33(j).
- (g) As part of its application, and in any event before the receipt of Restricted Data or classified National Security Information or the issuance of a renewed license, the applicant shall agree in writing that it will not permit any individual to have access to or any facility to possess Restricted Data or classified National Security Information until the individual and/or facility has been approved for such access under the provisions of 10 CFR Parts 25 and/or 95. The agreement of the applicant in this regard shall be deemed part of the renewed license, whether so stated therein or not.

[60 FR 22491, May 8, 1995, as amended at 62 FR 17690, Apr. 11, 1997]

#### **§ 54.19 Contents of application--general information.**

- (a) Each application must provide the information specified in 10 CFR 50.33(a) through (e), (h), and (i). Alternatively, the application may incorporate by reference other documents that provide the information required by this section.
- (b) Each application must include conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license.

#### **§ 54.21 Contents of application--technical information.**

Each application must contain the following information:

- (a) An integrated plant assessment (IPA). The IPA must--
  - (1) For those systems, structures, and components within the scope of this part, as delineated in § 54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components--
    - (i) That perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and
    - (ii) That are not subject to replacement based on a qualified life or specified time period.
  - (2) Describe and justify the methods used in paragraph (a)(1) of this section.
  - (3) For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation.
- (b) CLB changes during NRC review of the application. Each year following submittal of the license renewal application and at least 3 months before scheduled completion of the NRC review, an amendment to the renewal application must be submitted that identifies any change to the CLB of the facility that materially affects the contents of the license renewal application, including the FSAR supplement.
- (c) An evaluation of time-limited aging analyses.

- (1) A list of time-limited aging analyses, as defined in § 54.3, must be provided. The applicant shall demonstrate that--
  - (i) The analyses remain valid for the period of extended operation;
  - (ii) The analyses have been projected to the end of the period of extended operation; or
  - (iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.
- (2) A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in § 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.
- (d) An FSAR supplement. The FSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation determined by paragraphs (a) and (c) of this section, respectively.

#### **§ 54.22 Contents of application--technical specifications.**

Each application must include any technical specification changes or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. The justification for changes or additions to the technical specifications must be contained in the license renewal application.

#### **§ 54.23 Contents of application--environmental information.**

Each application must include a supplement to the environmental report that complies with the requirements of Subpart A of 10 CFR Part 51.

#### **§ 54.25 Report of the Advisory Committee on Reactor Safeguards.**

Each renewal application will be referred to the Advisory Committee on Reactor Safeguards for a review and report. Any report will be made part of the record of the application and made available to the public, except to the extent that security classification prevents disclosure.

#### **§ 54.27 Hearings.**

A notice of an opportunity for a hearing will be published in the Federal Register in accordance with 10 CFR 2.105. In the absence of a request for a hearing filed within 30 days by a person whose interest may be affected, the Commission may issue a renewed operating license without a hearing upon 30-day notice and publication once in the *Federal Register* of its intent to do so.

#### **§ 54.29 Standards for issuance of a renewed license.**

A renewed license may be issued by the Commission up to the full term authorized by § 54.31 if the Commission finds that:

- (a) Actions have been identified and have been or will be taken with respect to the matters identified in Paragraphs (a)(1) and (a)(2) of this section, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the plant's CLB in order to comply with this paragraph are in accord with the Act and the Commission's regulations. These matters are:
  - (1) managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21(a)(1); and
  - (2) time-limited aging analyses that have been identified to require review under § 54.21(c).
- (b) Any applicable requirements of Subpart A of 10 CFR Part 51 have been satisfied.
- (c) Any matters raised under § 2.335 have been addressed.

[69 FR 2279, Jan. 14, 2004]

#### **§ 54.30 Matters not subject to a renewal review.**

- (a) If the reviews required by § 54.21 (a) or (c) show that there is not reasonable assurance during the current license term that licensed activities will be conducted in accordance with the CLB, then the licensee shall take measures under its current license, as appropriate, to ensure that the intended function of those systems, structures or components will be maintained in accordance with the CLB throughout the term of its current license.
- (b) The licensee's compliance with the obligation under Paragraph (a) of this section to take measures under its current license is not within the scope of the license renewal review.

#### **§ 54.31 Issuance of a renewed license.**

- (a) A renewed license will be of the class for which the operating license currently in effect was issued.
- (b) A renewed license will be issued for a fixed period of time, which is the sum of the additional amount of time beyond the expiration of the operating license (not to exceed 20 years) that is requested in a renewal application plus the remaining number of years on the operating license currently in effect. The term of any renewed license may not exceed 40 years.

(c) A renewed license will become effective immediately upon its issuance, thereby superseding the operating license previously in effect. If a renewed license is subsequently set aside upon further administrative or judicial appeal, the operating license previously in effect will be reinstated unless its term has expired and the renewal application was not filed in a timely manner.

(d) A renewed license may be subsequently renewed in accordance with all applicable requirements.

#### **§ 54.33 Continuation of CLB and conditions of renewed license.**

(a) Whether stated therein or not, each renewed license will contain and otherwise be subject to the conditions set forth in 10 CFR 50.54.

(b) Each renewed license will be issued in such form and contain such conditions and limitations, including technical specifications, as the Commission deems appropriate and necessary to help ensure that systems, structures, and components subject to review in accordance with § 54.21 will continue to perform their intended functions for the period of extended operation. In addition, the renewed license will be issued in such form and contain such conditions and limitations as the Commission deems appropriate and necessary to help ensure that systems, structures, and components associated with any time-limited aging analyses will continue to perform their intended functions for the period of extended operation.

(c) Each renewed license will include those conditions to protect the environment that were imposed pursuant to 10 CFR 50.36b and that are part of the CLB for the facility at the time of issuance of the renewed license. These conditions may be supplemented or amended as necessary to protect the environment during the term of the renewed license and will be derived from information contained in the supplement to the environmental report submitted pursuant to 10 CFR Part 51, as analyzed and evaluated in the NRC record of decision. The conditions will identify the obligations of the licensee in the environmental area, including, as appropriate, requirements for reporting and recordkeeping of environmental data and any conditions and monitoring requirements for the protection of the nonaquatic environment.

(d) The licensing basis for the renewed license includes the CLB, as defined in § 54.3(a); the inclusion in the licensing basis of matters such as licensee commitments does not change the legal status of those matters unless specifically so ordered pursuant to paragraphs (b) or (c) of this section.

#### **§ 54.35 Requirements during term of renewed license.**

During the term of a renewed license, licensees shall be subject to and shall continue to comply with all Commission regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, and 100, and the appendices to these parts that are applicable to holders of operating licenses.

#### **§ 54.37 Additional records and recordkeeping requirements.**

(a) The licensee shall retain in an auditable and retrievable form for the term of the renewed operating license all information and documentation required by, or otherwise necessary to document compliance with, the provisions of this part.

(b) After the renewed license is issued, the FSAR update required by 10 CFR 50.71(e) must include any systems, structures, and components newly identified that would have been subject to an aging management review or evaluation of time-limited aging analyses in accordance with § 54.21. This FSAR update must describe how the effects of aging will be managed such that the intended function(s) in § 54.4(b) will be effectively maintained during the period of extended operation.

#### **§ 54.41 Violations.**

(a) The Commission may obtain an injunction or other court order to prevent a violation of the provisions of the following acts--

(1) The Atomic Energy Act of 1954, as amended.

(2) Title II of the Energy Reorganization Act of 1974, as amended or

(3) A regulation or order issued pursuant to those acts.

(b) The Commission may obtain a court order for the payment of a civil penalty imposed under Section 234 of the Atomic Energy Act--

(1) For violations of the following--

(i) Sections 53, 57, 62, 63, 81, 82, 101, 103, 104, 107, or 109 of the Atomic Energy Act of 1954, as amended;

(ii) Section 206 of the Energy Reorganization Act;

(iii) Any rule, regulation, or order issued pursuant to the sections specified in paragraph (b)(1)(i) of this section;

(iv) Any term, condition, or limitation of any license issued under the sections specified in paragraph (b)(1)(i) of this section.

(2) For any violation for which a license may be revoked under Section 186 of the Atomic Energy Act of 1954, as amended.

## Appendix C

### USNRC Guidance Concerning Aging Effects & Aging Mechanisms

**Table C-1: Aging Effects** (Source: GALL Report - NUREG-1801)

Selected Definitions & Use of Terms for Describing and Standardizing Aging Effects	
Changes in dimensions	Changes in dimensions can result from void swelling.
Concrete cracking and spalling	Concrete cracking and spalling can result from freeze-thaw, aggressive chemical attack, and reaction with aggregates.
Crack growth	Increase in crack size, attributable to cyclic loading.
Cracking	This term is used in this document to be synonymous with the phrase "crack initiation and growth" in metallic substrates. Cracking in concrete can be caused by restraint shrinkage, creep, and aggressive environment.
Cracking, loss of bond, and loss of material (spalling, scaling)	Cracking, loss of bond, and loss of material (spalling, scaling) can be caused by corrosion of embedded steel in concrete.
Cracks; distortion; increase in component stress level	Within concrete structures, cracks, distortion, and increase in component stress level can be caused by settlement. Although settlement can occur in a soil environment, the symptoms can be manifested in either an air-indoor uncontrolled or air-outdoor environment.
Cumulative fatigue damage	Cumulative fatigue damage is due to fatigue, as defined by ASME Boiler and Pressure Vessel Code.
Degradation of insulator quality	The decrease in insulating capacity can result from the presence of salt deposits or surface contamination. Although this derives from an aging mechanism (presence of salt deposits or surface contamination) that may be due to temporary, transient environmental conditions, the net result may be long lasting and cumulative.
Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance; electrical failure	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance, electrical failure can result from mechanisms such as thermal or thermoxidative degradation of organics; radiation-induced oxidation, radiolysis and photolysis (UV sensitive materials only) of organics; moisture intrusion; and ohmic heating.
Expansion and cracking	Within concrete structures, expansion and cracking can result from reaction with aggregates.
Fatigue	Fatigue in copper fuse holder clamps can result from ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, oxidation.
Fretting or lockup	Fretting is an aging effect due to accelerated deterioration at the interface between contacting surfaces as the result of corrosion and slight oscillatory movement between the two surfaces. In essence, both fretting and lockup are due to mechanical wear.
Hardening and loss of strength	Hardening and loss of strength can result from elastomer degradation of seals and other elastomeric components. Elastomers can experience increased hardness, shrinkage, and loss of strength, due to weathering.
Increase in porosity and permeability, cracking, loss of material (spalling, scaling), loss of strength	Concrete can increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack. In concrete, loss of material (spalling, scaling) and cracking can result from freeze-thaw processes. Loss of strength can result from leaching of calcium hydroxide in the concrete.
Increased resistance of connection	Increased resistance of connection in electrical transmission conductors and connections can be caused by oxidation or loss of preload.
Ligament cracking	Steel tube support plates can experience ligament cracking due to corrosion.
Localized damage and breakdown of insulation leading to electrical failure	Localized damage in polymeric electrical conductor insulation leading to electrical failure can be due to a number of aging mechanisms including moisture intrusion, and the formation of water trees. Based on operating experience, localized damage

Selected Definitions & Use of Terms for Describing and Standardizing Aging Effects	
	and breakdown of insulation may be exacerbated by manufacturing defects in the insulation of older electrical conductors, external damage, or damage due to poor installation practices.
Loosening of bolted connections	The loosening of bolted bus duct connections due to thermal cycling can result from ohmic heating.
Loss of fracture toughness	Loss of fracture toughness can result from various aging mechanisms including thermal aging, thermal aging embrittlement, and neutron irradiation embrittlement.
Loss of leak tightness	Steel airlocks can experience loss of leak tightness in closed position resulting from mechanical wear of locks, hinges, and closure mechanisms.
Loss of material	Loss of material may be due to general corrosion, boric acid corrosion, pitting corrosion, galvanic corrosion, crevice corrosion, erosion, fretting, flow-accelerated corrosion, MIC, fouling, selective leaching, wastage, wear, and aggressive chemical attack. In concrete structures, loss of material can also be caused by abrasion or cavitation or corrosion of embedded steel. For high voltage insulators, loss of material can be attributed to mechanical wear or wind-induced abrasion and fatigue due to wind blowing on transmission conductors.
Loss of material, loss of form	In earthen water-control structures, the loss of material and loss of form can result from erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage.
Loss of preload	Loss of preload due to gasket creep, thermal effects (including differential expansion and creep or stress relaxation), and self-loosening (which includes vibration, joint flexing, cyclic shear loads, thermal cycles) is an aging effect/mechanism accepted by industry as being within the scope of license renewal.
Loss of prestress	Loss of prestress in structural steel anchorage components can result from relaxation, shrinkage, creep, or elevated temperatures.
Reduction in foundation strength, cracking, differential settlement	Reduction in foundation strength, cracking, and differential settlement can result from erosion of porous concrete subfoundation.
Reduction of heat transfer	Reduction of heat transfer from fouling by the buildup, from whatever source, on the heat transfer surface. Although in heat exchangers, the tubes are the primary heat transfer component, heat exchanger internals including tubesheets and fins contribute to heat transfer and may be affected by the reduction of heat transfer due to fouling.
Reduction of strength and modulus	In concrete, reduction of strength and modulus can be attributed to elevated temperatures (>150°F general; >200°F local).
Reduction or loss of isolation function	Reduction or loss of isolation function in polymeric vibration isolation elements can result from elastomers exposed to radiation hardening, temperature, humidity, sustained vibratory loading.
Wall thinning	This is the term used to describe the specific type of loss of material due to flow-accelerated corrosion.

Table C-2: *Aging Mechanisms* (Source: GALL Report - NUREG-1801)

Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms	
Term	Aging Mechanism Definition as used in the GALL Report
Abrasion	As water migrates over a concrete surface, it may transport material that can abrade the concrete. The passage of water may also create a negative pressure at the water/air to concrete interface that can result in abrasion and cavitation degradation of the concrete. This may result in pitting or aggregate exposure due to loss of cement paste.
Aggressive chemical attack	Concrete, being highly alkaline ( $\text{pH} > 12.5$ ) is degraded by strong acids. Chlorides and sulfates of potassium, sodium, and magnesium may attack concrete, depending concentration in soil/ground water. Exposed surfaces of structures may be subject to sulfur-based acid-rain degradation. Minimum degradation thresholds are 500 ppm chlorides and 1500 ppm sulfates.
Boric acid corrosion	Corrosion by boric acid, which can occur where there is borated water leakage in an environment described as air with borated water leakage. See also Corrosion.
Cavitation	Formation and instantaneous collapse of innumerable tiny voids or cavities within a liquid subjected to rapid and intense pressure changes. Cavitation caused by severe turbulent flow can potentially lead to cavitation damage.
Chemical contamination	Degradation due to presence of chemical constituents.
Corrosion	Chemical or electrochemical reaction between a material, usually a metal, and its environment that produces a deterioration of the material and its properties.
Corrosion of embedded steel	If pH of the concrete in which steel is embedded is reduced ( $\text{pH} < 11.5$ ) by intrusion of aggressive ions (e.g., chlorides $> 500$ ppm) in the presence of oxygen, embedded steel corrosion may occur. A reduction in pH may be caused by the leaching of alkaline products through cracks, entry of acidic materials, or carbonation. Chlorides may also be present in the constituents of the original concrete mix. The severity of the corrosion is affected by the properties and types of cement, aggregates, and moisture content.
Creep	Creep, for a metallic material, refers to a time-dependent continuous deformation process under constant stress. It is an elevated temperature process and is not a concern for low alloy steel below 700°F, for austenitic alloys below 1000°F, and for Ni-based alloys below 1800°F. Creep, in concrete, is related to the loss of absorbed water from the hydrated cement paste. It is a function of modulus of elasticity of the aggregate. It may result in loss of prestress in the tendons used in prestressed concrete containment.
Crevice Corrosion	Localized corrosion of a metal surface at, or immediately adjacent to, an area that is shielded from full exposure to the environment, because of close proximity between the metal and the surface of another material. Crevice corrosion occurs in a wetted or buried environment when a crevice or area of stagnant or low flow exists that allows a corrosive environment to develop in a component. It occurs most frequently in joints and connections, or points of contact between metals and non-metals, such as gasket surfaces, lap joints, and under bolt heads. Carbon steel, cast iron, low alloy steels, stainless steel, copper, and nickel base alloys are all susceptible to crevice corrosion. Steel can be subject to crevice corrosion in some cases after lining/cladding degradation.
Cyclic loading	One source of cyclic loading is due to periodic application of pressure loads and forces due to thermal movement of piping transmitted through penetrations and structures to which penetrations are connected. The typical result of cyclic loads on metal components is fatigue cracking and failure; however, the cyclic loads may also cause deformation that results in functional failure.
Deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	Seals, gaskets, and moisture barriers (caulking, flashing, and other sealants) are subject to loss of sealing and leakage through containment caused by aging
Distortion	The aging mechanism of distortion can be caused by time dependent strain, or gradual elastic and plastic deformation of metal that is under constant stress at a value lower than its normal yield strength.
Elastomer degradation	Elastomer materials are substances whose elastic properties are similar to that of natural rubber. The term elastomer is sometimes used to technically distinguish synthetic rubbers and rubber-like plastics from natural rubber. Degradation may include cracking, crazing, fatigue breakdown, abrasion, chemical attacks, and weathering. [20, 21] Elastomer hardening refers to the degradation in elastic properties of the elastomer.

**Selected Definitions & Use of Terms  
for Describing and Standardizing Aging Mechanisms**

Term	Aging Mechanism Definition as used in the GALL Report
Electrical transients	An electrical transient is a stressor caused by a voltage spike that can contribute to aging degradation. Certain types of high-energy electrical transients can contribute to electromechanical forces ultimately resulting in fatigue or loosening of bolted connections. Transient voltage surges are a major contributor to the early failure of sensitive electrical components.
Elevated temperature	In concrete, reduction of strength and modulus can be attributed to elevated temperatures (>150°F general; >200°F local).
Erosion	Progressive loss of material from a solid surface due to mechanical interaction between that surface and a fluid, a multi-component fluid, or solid particles carried with the fluid.
Erosion settlement	Erosion (as defined above). Settlement of containment structure may occur during the design life due to changes in the site conditions, e.g., due to erosion or changes in the water table. The amount of settlement depends on the foundation material, and is generally determined by survey. Another term is erosion of the porous concrete sub-foundation.
Erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	In earthen water-control structures, the loss of material and loss of form can result from erosion, settlement, sedimentation, frost action, waves, currents, surface Run-off, and seepage.
Fatigue	A phenomenon leading to fracture under repeated or fluctuating stresses having a maximum value less than the tensile strength of the material. Fatigue fractures are progressive, and grow under the action of the fluctuating stress. Fatigue due to vibratory and cyclic thermal loads is defined as the structural degradation that can occur as a result of repeated stress/strain cycles caused by fluctuating loads, e.g., from vibratory loads, and temperatures, giving rise to thermal loads. After repeated cyclic loading of sufficient magnitude, micro-structural damage may accumulate, leading to macroscopic crack initiation at the most vulnerable regions. Subsequent mechanical or thermal cyclic loading may lead to growth of the initiated crack. Vibration may result in component cyclic fatigue, as well as in cutting, wear, and abrasion, if left unabated. Vibration is generally induced by external equipment operation. It may also result from flow resonance or movement of pumps or valves in fluid systems. Crack initiation and growth resistance is governed by factors including stress range, mean stress, loading frequency, surface condition, and the presence of deleterious chemical species.
Flow-accelerated corrosion (FAC)	Also termed erosion-corrosion. A co-joint activity involving corrosion and erosion in the presence of a moving corrosive fluid, leading to the accelerated loss of material.
Fouling	An accumulation of deposits. This term includes accumulation and growth of aquatic organisms on a submerged metal surface and also includes the accumulation of deposits, usually inorganic, on heat exchanger tubing. Biofouling, as a subset of fouling, can be caused by either macro-organisms (such as barnacles, Asian clams, zebra mussels, and others found in fresh and salt water) or micro-organisms, e.g., algae. Fouling can also be categorized as particulate fouling (sediment, silt, dust, and corrosion products), marine biofouling, or macrofouling, e.g., peeled coatings, debris, etc. Fouling in a raw water system can occur on the piping, valves, and heat exchangers. Fouling can result in a reduction of heat transfer, loss of material, or a reduction in the system flow rate (this last aging effect is considered active and thus is not in the purview of license renewal).
Freeze-Thaw, frost action	Repeated freezing and thawing is known to be capable of causing severe degradation to the concrete characterized by scaling, cracking, and spalling. The cause of this phenomenon is water freezing within the pores of the concrete, creating hydraulic pressure that, if unrelieved, will lead to freeze-thaw degradation. Factors that enhance the resistance of concrete to freeze-thaw degradation are a) adequate air content (e.g., within ranges specified in ACI 301-84), b) low permeability, c) protection until adequate strength has developed, and d) surface coating applied to frequently wet-dry surfaces.
Fretting	Aging effect due to accelerated deterioration at the interface between contacting surfaces as the result of corrosion, and slight oscillatory movement between the two surfaces.
Galvanic corrosion	Accelerated corrosion of a metal because of an electrical contact with a more noble metal or nonmetallic conductor in a corrosive electrolyte. Also called bimetallic corrosion, contact corrosion, dissimilar metal corrosion, or two-metal corrosion. Galvanic corrosion is an applicable aging mechanism for steel materials coupled to more noble metals in heat exchangers; galvanic corrosion of copper is of concern when coupled with the nobler stainless

**Selected Definitions & Use of Terms  
for Describing and Standardizing Aging Mechanisms**

Term	Aging Mechanism Definition as used in the GALL Report
	steel.
General corrosion	Also known as uniform corrosion, corrosion proceeds at approximately the same rate over a metal surface. Loss of material due to general corrosion is an aging effect requiring management for low alloy steel, carbon steel, and cast iron in outdoor environments.
Intergranular stress corrosion cracking (IGSCC)	SCC in which the cracking occurs along grain boundaries.
Leaching of calcium hydroxide	Water passing through cracks, inadequately prepared construction joints, or areas that are not sufficiently consolidated during placing may dissolve some calcium containing products, of which calcium hydroxide is the most-readily soluble, in concrete. Once the calcium hydroxide has been leached away, other cementitious constituents become vulnerable to chemical decomposition, finally leaving only the silica and alumina gels behind with little strength. The water's aggressiveness in the leaching of calcium hydroxide depends on its salt content and temperature. This leaching action is effective only if the water passes through the concrete.
Mechanical loading	Applied loads of mechanical origins rather than from other sources, such as thermal.
Microbiologically influenced corrosion (MIC)	Any of the various forms of corrosion influenced by the presence and activities of such microorganisms as bacteria, fungi, and algae, and/or the products produced in their metabolism. Degradation of material that is accelerated due to conditions under a biofilm or microfouling tubercle, for example, anaerobic bacteria that can set up an electrochemical galvanic reaction or inactivate a passive protective film, or acid-producing bacterial that might produce corrosive metabolites.
Moisture intrusion	Influx of moisture through any viable process.
Ohmic heating	Ohmic heating is induced by current flow through a conductor and can be calculated using first principles of electricity and heat transfer. Ohmic heating is a thermal stressor and can be induced in situations, such as conductors passing through electrical penetrations. Ohmic heating is especially significant for power circuit penetrations.
Overload	Overload is one of the aging mechanisms that can cause loss of mechanical function in piping and components, such as constant and variable load spring hangers, guides, stops, sliding surfaces, design clearances, vibration isolators, fabricated from steel or other materials, such as Lubrite
Oxidation	Two types of reactions a) reaction in which there is an increase in valence resulting from a loss of electrons, or b) a corrosion reaction in which the corroded metal forms an oxide.
Photolysis	Chemical reactions induced or assisted by light.
Pitting corrosion	Localized corrosion of a metal surface, confined to a point or small area, which takes the form of cavities called pits.
Plastic deformation	Time-dependent strain, or gradual elastic and plastic deformation, of metal that is under constant stress at a value lower than its normal yield strength.
Presence of any salt deposits	The surface contamination resulting from the aggressive environment associated with the presence of any salt deposits can be an aging mechanism causing the aging effect of degradation of insulator quality. Although this aging mechanism may be due to temporary, transient environmental conditions, the net result may be long-lasting and cumulative for plants located in the vicinity of saltwater bodies.
Radiolysis	Chemical reactions induced or assisted by radiation. Radiolysis and photolysis aging mechanisms can occur in UV-sensitive organic materials.
Reaction with aggregate	The presence of reactive alkalis in concrete, can lead to subsequent reactions with aggregates that may be present. These alkalis are introduced mainly by cement, but also may come from admixtures, salt-contamination, seawater penetration, or solutions of deicing salts. These reactions include alkali-silica reactions, cement-aggregate reactions, and aggregate-carbonate reactions. These reactions may lead to expansion and cracking.
Restraint shrinkage	Restraint shrinkage can cause cracking in concrete transverse to the longitudinal construction joint.
Selective leaching	Also known as dealloying, e.g., dezincification or graphitic corrosion. Selective corrosion of one or more components of a solid solution alloy.
Settlement	Settlement of structures may occur during the design life due to changes in the site conditions, e.g., the water table. The amount of settlement depends on the foundation material and is



**Selected Definitions & Use of Terms  
for Describing and Standardizing Aging Mechanisms**

Term	Aging Mechanism Definition as used in the GALL Report
	generally determined by survey.
Stress corrosion cracking (SCC)	Cracking of a metal produced by the combined action of corrosion and tensile stress (applied or residual).
Stress relaxation	Many of the bolts in reactor internals are stressed to a cold initial preload. When subject to high operating temperatures, over time, these bolts may loosen and the preload may be lost. Radiation can also cause stress relaxation, in highly stressed members such as bolts. Relaxation in structural steel anchorage components can be an aging mechanism contributing to the aging effect of loss of prestress.
Thermal aging embrittlement	Also termed thermal aging or thermal embrittlement. At operating temperatures of 500 to 650°F, cast austenitic stainless steels (CASS) exhibit a spinoidal decomposition of the ferrite phase into ferrite-rich and chromium-rich phases. This may give rise to significant embrittlement, i.e., reduction in fracture toughness, depending on the amount, morphology, and distribution of the ferrite phase and the composition of the steel. Thermal aging of materials other than CASS is a time- and temperature-dependent degradation mechanism that decreases material toughness. It includes temper embrittlement and strain aging embrittlement. Ferritic and low alloy steels are subject to both of these embrittlement, but wrought stainless steel is not affected by either of the processes.
Thermal effects, gasket creep, and self-loosening	Loss of preload due to gasket creep, thermal effects (including differential expansion and creep or stress relaxation), and self-loosening (which includes vibration, joint flexing, cyclic shear loads, thermal cycles) is within the scope of license renewal.
Thermal and mechanical loading	Loads (stress) due to mechanical or thermal (temperature) sources.
Thermal fatigue	Thermal (temperature) fatigue can result from phenomena such as thermal loading, thermal cycling, where there is cycling of the thermal loads and thermal stratification. Thermal stratification is a thermohydraulic condition with definitive hot and cold water boundary inducing thermal fatigue of the piping. Turbulent penetration is a thermo-hydraulic condition where hot and cold water mix as a result of turbulent flow conditions, leading to thermal fatigue of the piping.
Water trees	Water trees occur when the insulating materials are exposed to long-term, continuous electrical stress and moisture; these trees eventually result in breakdown of the dielectric and ultimate failure. The growth and propagation of water trees is somewhat unpredictable. Water treeing is a degradation and long-term failure phenomenon.
Wear	Wear is defined as the removal of surface layers due to relative motion between two surfaces or under the influence of hard abrasive particles. Wear occurs in parts that experience intermittent relative motion, frequent manipulation, or in clamped joints where relative motion is not intended but may occur due to a loss of the clamping force.
Weathering	Degradation of external surfaces of materials when exposed to outside environment.

## Appendix D

### Aging Management Program Example – Concrete Structures Monitoring

GALL Report (NUREG-1801 Vol 2)

#### XI.S2 ASME SECTION XI, SUBSECTION IWL

##### Program Description

10 CFR 50.55a imposes the examination requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWL for reinforced and prestressed concrete containments (Class CC). The scope of IWL includes reinforced concrete and unbonded post-tensioning systems. This evaluation covers both the 1992 edition with the 2001 edition<sup>1</sup> including the 2002 and 2003 Addenda, as approved in 10 CFR 50.55a. ASME Code Section XI, Subsection IWL and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing mandated program applicable to managing aging of containment reinforced concrete and unbonded post-tensioning systems for license renewal.

The primary inspection method specified in IWL is visual examination (VT-3C, VT-1, VT-1C). For prestressed containments, tendon wires are tested for yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is analyzed for alkalinity, water content, and soluble ion concentrations. Prestressing forces are measured in selected sample tendons. IWL specifies acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found.

The evaluation of 10 CFR 50.55a and Subsection IWL as an aging management program (AMP) for license renewal is provided below.

##### Evaluation and Technical Basis

- 1. Scope of Program:** Subsection IWL-1000 specifies the components of concrete containments within its scope. The components within the scope of Subsection IWL are reinforced concrete and unbonded post-tensioning systems of Class CC containments, as defined by CC-1000. Subsection IWL exempts from examination portions of the concrete containment that are inaccessible (e.g., concrete covered by liner, foundation material, or backfill, or obstructed by adjacent structures or other components).  
  
10 CFR 50.55a(b)(2)(viii) specifies additional requirements for inaccessible areas. It states that the licensee is to evaluate the acceptability of concrete in inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. Steel liners for concrete containments and their integral attachments are not within the scope of Subsection IWL, but are included within the scope of Subsection IWE.
- 2. Preventive Action:** No preventive actions are specified; Subsection IWL is a monitoring program. If a coating program is currently credited for managing the effects of aging of concrete surfaces, then the program is to be continued during the period of extended operation.
- 3. Parameters Monitored or Inspected:** Table IWL-2500-1 specifies two categories for examination of concrete surfaces: Category L-A for all concrete surfaces and Category L-

<sup>1</sup> An applicant may rely on a different version of the ASME Code, but should justify such use. An applicant may wish to refer to the SOC for an update of 10 CFR § 50.55a to justify use of a more recent edition of the Code.

B for concrete surfaces surrounding tendon anchorages. Both of these categories rely on visual examination methods. Concrete surfaces are examined for evidence of damage or degradation, such as concrete cracks. IWL-2510 specifies that concrete surfaces are examined for conditions indicative of degradation, such as those defined in ACI 201.1R-77. Table IWL-2500-1 also specifies Category L-B for test and examination requirements for unbonded post tensioning systems. Tendon anchorage and wires or strands are visually examined for cracks, corrosion, and mechanical damage. Tendon wires or strands are also tested for yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is tested by analysis for alkalinity, water content, and soluble ion concentrations.

4. **Detection of Aging Effects:** The frequency and scope of examinations specified in 10 CFR 50.55a and Subsection IWL ensure that aging effects would be detected before they would compromise the design-basis requirements. The frequency of inspection is specified in IWL-2400. Concrete inspections are performed in accordance with Examination Category L-A. Under Subsection IWL, inservice inspections for concrete and unbonded post-tensioning systems are required at one, three, and five years following the structural integrity test. Thereafter, inspections are performed at five-year intervals. For sites with two plants, the schedule for inservice inspection is provided in IWL-2421. In the case of tendons, only a sample of the tendons of each tendon type requires examination at each inspection. The tendons to be examined during an inspection are selected on a random basis. Table IWL-2521-1 specifies the number of tendons to be selected for each type (e.g., hoop, vertical, dome, helical, and inverted U) for each inspection period. The minimum number of each tendon type selected for inspection varies from 2 to 4%. Regarding detection methods for aging effects, all concrete surfaces receive a visual VT-3C examination. Selected areas, such as those that indicate suspect conditions and areas surrounding tendon anchorages, receive a more rigorous VT-1 or VT-1C examination. Prestressing forces in sample tendons are measured. In addition, one sample tendon of each type is detensioned. A single wire or strand is removed from each detensioned tendon for examination and testing. These visual examination methods and testing would identify the aging effects of accessible concrete components and prestressing systems in concrete containments.
5. **Monitoring and Trending:** Except in inaccessible areas, all concrete surfaces are monitored on a regular basis by virtue of the examination requirements. For prestressed containments, trending of prestressing forces in tendons is required in accordance with paragraph (b)(2)(viii) of 10 CFR 50.55a. In addition to the random sampling used for tendon examination, one tendon of each type is selected from the first-year inspection sample and designated as a common tendon. Each common tendon is then examined during each inspection. This procedure provides monitoring and trending information over the life of the plant. 10 CFR 50.55a and Subsection IWL also require that prestressing forces in all inspection sample tendons be measured by lift-off tests and compared with acceptance standards based on the predicted force for that type of tendon over its life.
6. **Acceptance Criteria:** IWL-3000 provides acceptance criteria for concrete containments. For concrete surfaces, the acceptance criteria rely on the determination of the "Responsible Engineer" (as defined by the ASME Code) regarding whether there is any evidence of damage or degradation sufficient to warrant further evaluation or repair. The acceptance criteria are qualitative; guidance is provided in IWL-2510, which references ACI 201.1R-77 for identification of concrete degradation. IWL-2320 requires that the Responsible Engineer be a registered professional engineer experienced in evaluating

the inservice condition of structural concrete and knowledgeable of the design and construction codes and other criteria used in design and construction of concrete containments. Quantitative acceptance criteria based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R may also be used to augment the qualitative assessment of the responsible engineer. The acceptance standards for the unbonded post-tensioning system are quantitative in nature. For the post-tensioning system, quantitative acceptance criteria are given for tendon force and elongation, tendon wire or strand samples, and corrosion protection medium. 10 CFR 50.55a and Subsection IWL do not define the method for calculating predicted tendon prestressing forces for comparison to the measured tendon lift-off forces. The predicted tendon forces are to be calculated in accordance with Regulatory Guide 1.35.1, which provides an acceptable methodology for use through the period of extended operation.

7. **Corrective Actions:** Subsection IWL specifies that items for which examination results do not meet the acceptance standards are to be evaluated in accordance with IWL-3300 "Evaluation" and described in an engineering evaluation report. The report is to include an evaluation of whether the concrete containment is acceptable without repair of the item and if repair is required, the extent, method, and completion date of the repair or replacement. The report also identifies the cause of the condition and the extent, nature, and frequency of additional examinations. Subsection IWL also provides repair procedures to follow in IWL-4000. This includes requirements for the concrete repair, repair of reinforcing steel, and repair of the post-tensioning system. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.
8. **Confirmation Process:** When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. As part of this evaluation, IWL-3300 specifies that the engineering evaluation report include the extent, nature, and frequency of additional examinations. IWL-4000 specifies the requirements for examination of areas that are repaired. Pressure tests following repair or modifications are in accordance with IWL-5000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.
9. **Administrative Controls:** IWA-1400 specifies the preparation of plans, schedules, and inservice inspection summary reports. In addition, written examination instructions and procedures, verification of qualification level of personnel who perform the examinations, and documentation of a quality assurance program are specified. IWA-6000 specifically covers the preparation, submittal, and retention of records and reports. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.
10. **Operating Experience:** ASME Section XI, Subsection IWL was incorporated into 10 CFR 50.55a in 1996. Prior to this time, operating experience pertaining to degradation of reinforced concrete and prestressing systems in concrete containments was gained through the inspections required by 10 CFR Part 50, Appendix J and ad hoc inspections conducted by licensees and the Nuclear Regulatory Commission (NRC). Recently, NRC Information Notice (IN) 99-10 described occurrences of degradation in prestressing systems. The program is to consider the degradation concerns described in this generic communication. Implementation of Subsection IWL, in accordance with 10 CFR 50.55a, is

a necessary element of aging management for concrete containments through the period of extended operation.

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NRC Information Notice 99-10, Revision 1, *Degradation of Prestressing Tendon Systems in Prestressed Concrete Containment*, U.S. Nuclear Regulatory Commission, October 7, 1999.

# Appendix E

## License Renewal Inspection Policy and Guidance\*

### USNRC Inspection Manual Chapter (MC) 2516 – Policy and Guidance for the License Renewal Inspection Programs (Edited)

#### 2516-01 PURPOSE

The purpose of MC 2516 is to document policy and guidance for review and inspection activities associated with the License Renewal Inspection Program (LRIP). The LRIP is the process used by Nuclear Regulatory Commission (NRC) staff, region, and consultants to verify the accuracy of the aging management programs and activities associated with an applicant's request for a renewed license for a commercial nuclear power plant beyond the initial licensing period under Title 10 of the Code of Federal Regulation, (10 CFR) Part 54.

#### 2516-02 POLICY AND OBJECTIVES

02.01 The basic policies, excerpted from the Statements of Consideration of the License Renewal Rule, and objectives used in the development and implementation of the LRIP are as follows:

- a. The NRC exists to assure that the public health and safety, the common defense and security, and the environment are protected.
- b. With respect to license renewal of a commercial nuclear power plant, the NRC has established the following two basic principles:
  1. The first principle of license renewal is that with the exception of age-related degradation and possibly a few other issues related to safety only during extended operation of nuclear power plants, the existing regulatory process is adequate to ensure that the licensing bases of all currently operating plants provide and maintain an acceptable level of safety so that operation will not be inimical to public health and safety or common defense and security.
  2. The second and equally important principle of license renewal holds that the plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term. This would be accomplished, in part, through a program of age-related degradation management.
- c. An applicant for license renewal should rely on the plant's current licensing basis (CLB), actual plant-specific experience, industry-wide operating experience, as appropriate, and existing engineering evaluations to determine those systems, structures, and components that are the initial focus of the license renewal review.
- d. The detrimental effects of aging affecting passive structures and components are less apparent than the detrimental effects of aging affecting structures and components that perform their intended functions with moving parts or a change in configuration or properties (active structures and components). Therefore, the aging management review of passive structures and components is needed to provide reasonable assurance that their intended functions are maintained consistent with the CLB during the period of extended operation.
- e. For the purpose of license renewal, an applicant can generically exclude, from its integrated plant assessment, the aging management review of the following: 1) active structures and components, and 2) structures and components that are replaced, based on qualified life or specified time period, when the replacement frequency is less than 40 years ("short-lived"). In addition, some components are both active and passive. Components that are passive, or both active and passive, must be included within the scope of components requiring an aging management review based on the intended function(s) that is performed without moving parts or change in configuration or properties.

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\* Note: A copy of the related USNRC License Renewal Inspection Procedure 71002 is provided in Attachment D of the CGI Report 06-22, *Condition Monitoring of Passive Systems, Structures, and Components*

- f. Postulated failures that could result from system interdependencies that are not part of the CLB and that have not been previously experienced need not be considered as part of a license renewal application (LRA). However, for some license renewal applicants, postulated failures that are part of the CLB may require consideration of more than the first level support systems.

02.02 The objectives of the LRIP are as follows:

- a. The LRIP will provide the guidance for the inspection of license renewal programs, documentation, and activities necessary for the staff to make a finding that an applicant's LRA, aging management programs (AMPs), implementation activities, and on-site documentation provide reasonable assurance that the effects of aging will be effectively managed consistent with the CLB during the period of extended operation.
- b. The LRIP will also provide the guidance for assessing the adequacy of implemented AMPs to effectively manage the effects of aging, consistent with the licensee's CLB, after the renewed license is issued.

2516-03 DEFINITIONS

Current licensing basis is the set of NRC requirements applicable to a specific plant and a licensee's written regulatory commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent final safety analysis report (FSAR) as required by 10 CFR 50.71; and the licensee's commitments remaining in effect that were made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports.

Regulatory Commitment is an explicit statement made by a licensee (or applicant) to take a specific action agreed to or volunteered by a licensee, and that has been submitted in writing on the docket to the Commission.

Integrated Plant Assessment (IPA) is a licensee assessment that demonstrates that a nuclear power plant facility's structures and components requiring aging management review in accordance with §54.21(a) for license renewal have been identified and that the effects of aging on the functionality of such structures and components will be managed to maintain the CLB such that there is an acceptable level of safety during the period of extended operation.

Nuclear power plant means a nuclear power facility of a type described in 10 CFR 50.21(b) or 50.22.

2516-06 LICENSE RENEWAL INSPECTION PROGRAM

06.01 Purpose.

The fundamental task of the LRIP is to ensure that there is reasonable assurance that the effects of aging will be managed consistent with the CLB during the period of extended operation. The program objectives derived from that task are as follows:

- a. To provide a basis for recommending issuance or denial of a renewed license.
- b. To identify weaknesses within an applicant's overall license renewal program or an individual AMP that fail to provide reasonable assurance that the applicable aging effects will be adequately managed during the period of extended operation.
- c. To determine the status of compliance with 10 CFR Part 54 and other areas relating to maintaining and operating the plant such that the continued operation beyond the current licensing term will not be inimical to the public health and safety.

06.02 Independent Inspection Policy.

These inspections should be conducted in accordance with inspection procedure IP 71002. However, it is not possible to anticipate all the unique circumstances that might be encountered during the course of a particular inspection and, therefore, individual inspectors are expected to exercise initiative in conducting inspections based on their expertise and experience to assure that all the inspection objectives are met. If in the course of conducting an inspection, current potential safety concerns or compliance issues outside

the scope of the procedure being executed are identified, the concerns should be pursued to the extent necessary to understand the issue and then they will be turned over to the Senior Resident Inspector for further follow-up inspection.

#### 06.03 License Renewal Review Program.

The license renewal review program consists of an LRA review and site inspections. The LRA review is primarily a headquarters review performed by NRR to ensure that the applicant meets the technical and regulatory requirements of the rule, and to verify that the format and content of the application meet the requirements of the rule. The regional staff and inspection team members will become familiar with the LRA in preparation for inspections to provide operational and performance input in the application review, to assess the applicant's commitments against their past performance and experience, and in preparation to provide a regional recommendation to grant or deny approval for the applicant's request for a renewed license.

#### 06.04 Site-Inspections.

The site inspections are assessments of an applicant's implementation of and compliance with 10 CFR Part 54 requirements. All inspection teams will be led by the regions and any NRR supporting staff will be detailed to the region for the period of time necessary to prepare, inspect, and document inspection activities. The site inspections will be performed by a team inspection in the areas of the scoping and screening activities, observation of the condition of plant equipment, and implementation of the aging management programs and review of associated documentation. By observing the current condition of plant equipment in the scope of license renewal, inspectors may identify the effects of aging not previously recognized. Such observations allow the inspectors to evaluate the success of previously implemented plant programs, which are being credited for license renewal AMPs. The site-inspection activities will be performed using IP 71002 "License Renewal Inspections."

#### 06.05 Post Renewal Site-Inspections.

Site inspections of AMP implementation conducted after the approval of the renewed license will be conducted in accordance with IP 71003 "Post-Approval Site Inspection for License Renewal." These inspections will verify the licensee's continued compliance with 10 CFR Part 50 and implementation of commitments related to the LRA.

#### 06.06 Inspection Documentation.

Inspections will be documented with inspection reports sent to the applicant and made publicly available in ADAMS. Attachments to IMC 2516 provide guidance on the preparation of documents related to the site inspection. Attachment 1, "Region Notification of Plant Readiness For License Renewal," provides a region with guidance on how to prepare its overall evaluation of inspection activities performed on an applicant for license renewal. Attachment 2, "Sample License Renewal Inspection Letter," is a sample letter of an overall evaluation of the inspection completion. The results of site team inspections will provide major input for the staff and regional recommendations to grant or deny an applicant's request for a renewed license.



## Appendix F

### Nuclear Related Aging Management and Life Extension Abbreviations and Acronyms

Abbreviation or Acronym	Description
AMP	Aging Management Program
AMR	Aging Management Review
ANSI	American Nuclear Standards Institute
ASME	American Society of Mechanical Engineers
BAW	Babcock and Wilcox
BIR	Benefit to Investment Ratio
BOP	Balance of Plant
BWROG	Boiling Water Reactor Owners Group
CBA	Cost Benefit Analysis
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CUF	Cumulative Usage Factor
DBD	Design Basis Document
DOE	U.S. Department of Energy
EPIX	Equipment Performance and Information Exchange
EPRI	Electrical Power Research Institute
EQ	Environmental Qualification
ER	Environmental Report
FHA	Fire Hazards Analysis and Fire Protection Program
FSAR	Final Safety Analysis Report
FSD	Functional System Description
GALL	Generic Aging Lessons Learned
IOE	Industry Operating Experience
INPO	Institute of Nuclear Power Operations
ISG	Interim Staff Guidance
ISI	In-Service Inspection
LCM	Life Cycle Management
LRA	License Renewal Application
LRR	License Renewal Rule
MIC	Microbiological Influenced Corrosion
MPFF	Maintenance Preventable Functional Failure
MR	Maintenance Rule
NEI	Nuclear Energy Institute
NMAC	Nuclear Maintenance Assist Center
NPAR	Nuclear Plant Aging Reports
NPV	Net Present Value
NRC	Nuclear Regulatory Commission (also USNRC)
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturer
PdM	Predictive (diagnostic) Maintenance

Abbreviation or Acronym	Description
PM	Preventive Maintenance
PRA	Probabilistic Risk Analysis
RAI	Request for Additional Information (NRC Questions)
RAW	Risk Achievement Worth
RMPFF	Repetitive MPFF
RRW	Risk Reduction Worth
SER	Safety Evaluation Report
SOC	Statement of Considerations
SPV	Single Point Vulnerability
SRP	Standard Review Plan
SRP-LR	Standard Review Plan for License Renewal
SSC	Systems, Structures and Components
TLAA	Time Limited Aging Analyses
USNRC	United States Nuclear Regulatory Commission
WANO	World Association of Nuclear Operators

## **Appendix G**

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### **Bibliography of Selected Nuclear Aging Management and Life Extension Reports**

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- PNL-5722, "Operating Experience and Aging Assessment of ECCS Pump Room Coolers"
- PNL-SA-18407, "Understanding and Managing Corrosion in Nuclear Power Plants"
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- EPRI NP-5836M, "BWR Pilot Plant Life Extension Study at the Monticello Plant: Interim Phase 2," October 1988
- EPRI NP-5911M and NP-5911SP, Acceptance Criteria for Structural Evaluation of Erosion-Corrosion Thinning in Carbon Steel Piping, July 1988
- EPRI NP-6541, "BWR Pilot Plant Life Extension Study at the Monticello Plant: Phase 2," September 1989
- EPRI TR-103835, "Pressurized Water Reactor Containment Structures License Renewal Industry Report," July 1994
- EPRI TR-103841, "The Low Voltage, In-Containment, Environmentally-Qualified Cable License Renewal Industry Report," July 1994
- EPRI TR-103842, "Class I Structures License Renewal Industry Report," July 1994
- EPRI TR-103844, "PWR Reactor Coolant System License Renewal Industry Report," July 1994
- EPRI TR-103893, "BWR Primary Coolant Pressure Boundary License Renewal Industry Report," July 1994
- Nuclear Energy Institute, NEI 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," Revision 3, dated March 2001
- SAND 93-7045, "Aging Management Guideline for Commercial Nuclear Power Plants – Pumps," March 1994
- SAND 93-7070, "Aging Management Guideline for Commercial Nuclear Power Plants – Heat Exchangers," June 1994
- SAND 96-0344, "Aging Management Guide for Commercial Nuclear Power Plants – Electrical Cables and Terminations," October 1996
- SAND 97-0343, "Aging Management Guide for Commercial Nuclear Power Plants – Tanks and Pools," February 1996

- SAND 98-XXXX, "Aging Management Guide for Commercial Nuclear Power Plants, Non-Reactor Coolant Pressure Boundary Piping and Tubing", Teledyne Draft Report, TR-89313, August 6, 1998

### **Selected Life Cycle Management Documents**

- EPRI, "Preventive Maintenance Basis", Version 4.0, Overview Report TR-106857-V40, November 1998
- EPRI, "Generic Communications Database", Version 3.0, Release 5.0, July 2002
- EPRI, "System Monitoring Database", (SysMon), Version 1.3, 1998.
- EPRI Life Cycle Management Planning Tool, Report No. 1001686, LcmPLATO, Version 1.0, June 2002
- EPRI Life Cycle Management Planning Tool, LcmVALUE, Beta Version 0.2, June 2002
- EPRI Technical Report 1000806, "Demonstration of Life Cycle Management Planning for Systems, Structures and Components" With Pilot Applications at Oconee and Prairie Island Nuclear Stations, January 2001
- EPRI Technical Report 1007426, "Life Cycle Management Planning Sourcebooks-Volume 7, Low Voltage Electrical Distribution System", December 2002
- EPRI Technical Report 1009153, "Life Cycle Management Plan For Circuit Breakers at Salem and Hope Creek Stations", September 2003
- EPRI Technical Report No. 1000014, "Circuit Breaker Maintenance Programmatic Considerations", February 2001
- European Industry Reliability Data Bank, EIReDA 1998, Crete University Press
- IEEE Standard 493-1997, "IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems", December 1997.
- INPO, Equipment Performance and Information Exchange 4.0 (EPIX Database)
- Institute for Nuclear Power Operation (INPO), "Equipment Reliability Process Description", AP-913, Revision 1, November 2001
- Nuclear Electric Insurance Limited (NEIL), Loss Control Standards, September 2002

January 24, 2003

Mr. John L. Skolds, President  
Exelon Nuclear  
Exelon Generation Company, LLC  
4300 Winfield Road  
Warrenville, Illinois 60555

SUBJECT: CLINTON POWER STATION  
NRC INSPECTION REPORT 50-461/02-10(DRS)

Dear Mr. Skolds:

On December 13, 2002, the NRC completed an inspection at your Clinton Power Station. The enclosed report documents the inspection findings, which were discussed with Mr. K. Polson and other members of your staff at the completion of the inspection.

The inspectors examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. Specifically, the inspection focused on the Evaluations of Changes, Tests, or Experiments per 10 CFR 50.59 and Permanent Plant Modifications.

No safety significant items were identified and no response to this inspection report is required.

In accordance with 10 CFR 2.790 of the NRC's Rules of Practice, a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at <http://www.nrc.gov/reading-rm/adams.html> (the Public Electronic Reading Room).

Sincerely,

/RA/

Ronald N. Gardner, Chief  
Electrical Engineering Branch  
Division of Reactor Safety

Docket No. 50-461  
License No. NPF-62

Enclosure: Inspection Report 50-461/02-10(DRS)

See Attached Distribution

Mr. John L. Skolds, President  
Exelon Nuclear  
Exelon Generation Company, LLC  
4300 Winfield Road  
Warrenville, Illinois 60555

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Sincerely,  
/RA/

Ronald N. Gardner, Chief  
Electrical Engineering Branch  
Division of Reactor Safety

Docket No. 50-461  
License No. NPF-62

Enclosure: Inspection Report 50-461/02-10(DRS)

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J. Skolds

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cc w/encl: Site Vice President - Clinton Power Station  
Clinton Power Station Plant Manager  
Regulatory Assurance Manager - Clinton  
Chief Operating Officer  
Senior Vice President - Nuclear Services  
Senior Vice President - Mid-West Regional Operating Group  
Vice President - Mid-West Operations Support  
Vice President - Licensing and Regulatory Affairs  
Director Licensing - Mid-West Regional Operating Group  
Manager Licensing - Clinton and LaSalle  
Senior Counsel, Nuclear, Mid-West Regional Operating Group  
Document Control Desk - Licensing

J. Skolds

-2-

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Clinton Power Station Plant Manager  
Regulatory Assurance Manager - Clinton  
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Vice President - Licensing and Regulatory Affairs  
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No: 50-461  
License No: NPF-62

Report No: 50-471/02-10(DRS)

Licensee: Exelon Generation Company, LLC

Facility: Clinton Power Station

Location: Route 54 West  
Clinton, IL 61727

Dates: December 9 through 13, 2002

Inspectors: H. Walker, Lead Inspector  
R. Winter, Engineering Inspector  
H. Anderson, Contract Inspector

Approved by: Ronald M. Gardner, Chief  
Electrical Engineering Branch  
Division of Reactor Safety

## **SUMMARY OF FINDINGS**

IR 05000471-02-10(DRS), Exelon Generation Company, LLC; on 12/09-13/02, Clinton Power Station; Evaluations of Changes, Tests, or Experiments per 10 CFR 50.59 and Permanent Plant Modifications.

The inspection was a one week baseline inspection of Permanent Plant Modifications and Evaluations of Changes, Tests, or Experiments. The inspection was conducted by regional engineering specialists, with the assistance of a mechanical consultant. No findings were identified during the inspection.

## REPORT DETAILS

### 1. REACTOR SAFETY

#### Cornerstone: Mitigating Systems

#### 1R02 Evaluations of Changes, Tests, or Experiments (71111.02)

##### Review of Evaluations and Screenings for Changes, Tests, or Experiments

##### a. Inspection Scope

The inspectors reviewed five 10 CFR 50.59 evaluations and nine screenings. These documents were reviewed to ensure consistency with the requirements of 10 CFR 50.59. The inspectors used Nuclear Energy Institute (NEI) 96-07, "Guidelines of 50.59 Evaluations," Revision 1, to determine acceptability of the completed evaluations, and screenings. The NEI document was endorsed by the NRC in Regulatory Guide 1.187, "Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments," November 2000. The inspectors also consulted Inspection Manual, Part 9900, 10 CFR GUIDANCE: 50.59. Documents reviewed during the inspection are listed at the end of the report.

##### b. Findings

No findings of significance were identified.

#### 1R17 Permanent Plant Modifications (71111.17)

##### 1 Review of Recent Permanent Plant Modifications

##### a. Inspection Scope

The inspectors reviewed eleven permanent plant modifications that were installed during the last two years. These changes affected various systems in the plant. The review of the records completed the activities required by Attachment 17 of NRC Inspection Procedure 71111. The modifications were reviewed to verify that the completed design changes were in accordance with specified design requirements and the licensing bases and to confirm that the changes did not affect the modified system or other systems' safety function. Calculations which were performed or revised to support the modifications were also reviewed. As applicable to the status of the modification, post-modification testing was reviewed to verify that the system, and associated support systems, functioned properly and that the modification accomplished its intended function. The inspectors also verified that the completed modifications did not place the plant in an increased risk configuration. The inspectors evaluated the modifications against the licensee's design basis documents and the updated final safety analysis report (UFSAR). The inspectors also used applicable industry standards, such as the American Society of Mechanical Engineers Code, to evaluate acceptability of the modifications.

In addition to the normal review of permanent plant modifications, the inspectors reviewed selected design changes and other licensee documents associated with the effects of the plant power up-rate on the flow accelerated corrosion (FAC) program. This review is discussed in this section of the report.

b. Findings

No findings of significance were identified.

2. Flow Accelerated Corrosion (FAC) Program

a. Inspection Scope

In accordance with Inspection Procedure 49001, "Inspection of Erosion-Corrosion/Flow-Accelerated-Corrosion Monitoring Programs," the inspectors reviewed documents and records to verify selected aspects of the FAC program. The review included associated design changes and calculations completed or revised to address the potential effects of the extended power up-rate (EPU) on the FAC program at the Clinton Power Plant. Evaluation of these documents also involved extensive discussions with licensee personnel.

In the review, the inspectors noted that Revision A of calculation 01065301, "CHECWORKS FAC Analysis," was confirmed to have incorporated inputs from the General Electric up-rate heat balance into the current FAC analysis. The Safety Evaluation Report (SER) related to the EPU was issued prior to completion of Revision A of the calculation; however, the SER summarized "in-progress" results provided by licensee personnel prior to issuance of Revision A of the calculation.

By reviewing documents and records, per Inspection Procedure 49001, "Inspection of Erosion-Corrosion/Flow-Accelerated-Corrosion Monitoring Programs," the inspectors verified the following aspects of the FAC program:

- The FAC program included a systematic method to predict system and component susceptibility, analyze inspection data to determine wall thinning rates, determine inspection intervals based on past inspection results, and repair or replace piping components.
- The program had defined criteria for selection of inspection locations.
- The program procedurally included measures to support effective monitoring and management of FAC effects during the life of the plant.
- The FAC program monitored the effect on FAC of expected changes in operating plant parameters as a result of the EPU in systems as identified in the SER, including main steam and attached piping, feedwater, and other pressure boundary piping.

- The program identified risk significant FAC concerns as a result of the EPU including identification of FAC program material replacements scheduled for installation during refueling outage RF09 in 2004.

The licensee personnel confirmed that the "in-progress" results discussed in the SER were conservative. The calculation results predicted wall thinning rates of 25 mils at 100 percent power and 27 mils at EPU conditions, an increase of approximately 8 percent.

Concerns raised by the inspectors were discussed with the licensee.

b. Findings

No findings of significance were identified.

4. **OTHER ACTIVITIES (OA)**

4OA2 Identification and Resolution of Problems

a. Inspection Scope

The team reviewed seventeen condition reports that were identified by licensee personnel and had been entered into the corrective action program. The inspectors reviewed these issues to verify an appropriate threshold for identifying issues and to evaluate the effectiveness of corrective actions related to the permanent plant design and evaluations for Changes, Tests, or Experiments issues. In addition, the condition report, written on an issue identified during the inspection, was reviewed to verify adequate problem identification and incorporation of the problem into the corrective action system. The specific corrective action documents that were sampled and reviewed by the team are listed in the attachment to this report.

b. Findings

No findings of significance were identified.

4OA6 Meetings

Exit Meeting

The inspectors presented the inspection results to Mr. K. J. Polson, and other members of licensee management, on December 13, 2002. The licensee acknowledged the inspection results presented. Licensee personnel were asked to identify any documents, materials, or information provided during the inspection that were considered proprietary. No proprietary information was identified.

## KEY POINTS OF CONTACT

### Licensee Management

K. Polson, Plant Manager  
K. Baker, Senior Manager Design Engineering  
R. Frantz, Regulatory Assurance  
W. Iliff, Regulator Assurance Manager  
R. Kerestes, Engineering  
J. Madden, Nuclear Oversight Manager  
P. Marcum, Engineering  
E. Schwertzer, Engineering  
R. Schmidt, Maintenance Director  
J. Williams, Site Engineering Director

### NRC

C. Brown, Resident Inspector  
R. Gardner, Chief, Electrical Engineering Branch, DRS  
P. Loudon, Senior Resident Inspector  
A. Stone, Chief, Projects Branch 4, DRP

## LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

### Opened

None

### Closed

None

### Discussed

None



## LIST OF DOCUMENTS REVIEWED

The following documents were selected and reviewed by the inspectors during the Clinton biennial inspection of Evaluations of Changes, Tests, or Experiments and Permanent Plant Modifications conducted from December 9 through 13, 2002. The inspection was conducted to accomplish the objectives and scope of the inspection and to support the findings and issues noted. The list may include documents prepared by others for the licensee. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety, but that selected portions of the documents were evaluated as part of the overall inspection effort. Also inclusion on this list does not imply NRC acceptance of the document, unless specifically stated in the body of the inspection report.

### 1R02 Evaluations of Changes, Tests, or Experiments

#### Evaluations

CL-2001-E-01890; DCP No. 333952 Temporary Modification, Defeat RR 'A' Runback; dated December 14, 2001

CL-2001-E-01900; DCP No. 334153 Temporary Modification, Manual RR 'A' FCV Position Control; dated December 14, 2001

CL-2002-E-00028; Activity/Document Number: CPS 3302.03 - Noble Metal Injection; Revision 1

CL-2002-E-00052; Clinton Unit 1 Cycle 9 Reload Core Design and Licensing; Revision 0

CL-2002-E-00520; Temporary Modification EC 338256, Temporarily Disable Turbine Control Valve #4; dated September 13, 2002

#### Screenings

CL-2001-S-0018; ECN 32439, Installation of Tie-In for WO Piping and Valves for the New Suppression Pool Cooling Heat Exchanger; dated March 22, 2001

CL-2001-S-0115; Reduction of Main Steam Line Radiation Monitors from Four to Two; dated October 25, 2001

CL-2001-S-01740; ORM 35-6, Setpoint Sign Changes; dated November 30, 2001

CL-2002-S-00210; USAR Change Package 8-303, USAR Change Package for Containment and Drywell Volume Corrections Including EPU; dated February 26, 2002

CL-2002-S-00510; USAR Change 10-095(change to 6.2.1.1.5.5 only), Evaluation of Change in the Analysis of the Small Break LOCA with Drywell Bypass Leakage; dated April 16, 2002

CL-2002-S-00780; EC337228, USAR Change 10-109, TS Bases Change, Instrumentation Aspects of Diesel Fuel Tank Level Requirements; dated June 27, 2002

LS-AA-104-1001; Reclassification of RCIC Pump Tech Spec Surveillance Parameters from Not Nominal to Nominal; dated May 20, 2002

LS-AA-104-1003; Replacement of Cylinder Indicator Valves on Div. 1 Diesel Generator - (1DG01KA); dated January 11, 2001

1005.06F001; Replace DG Air Start Solenoid Pilot Valves per ECNs 30444 and 30745; dated November 6, 1998

#### Condition Reports Written as a result of the Inspection

CR 00135358; Inconsistent Methods Were Used to Document the Results of 10 CFR 50.59 applicability Reviews for Modification; dated December 13, 2002

#### Condition Reports

CR 2-00-11-127; OD/OE Process/Procedure Does Not Provide Adequate Barriers to Assure Timely Corrective Actions; dated November 17, 2000

CR 2-01-06-017; 50.59 Screening Form Was Not Prepared; dated June 4, 2001

CR 2-01-05-157-0; Inadequate Implementation of LS-AA-104; dated May 15, 2001

CR 00099796; FP Diesel Tank Level Changed Without Documentation Bases; dated March 18, 2002

CR 00123080; Potential Expiration of TS 3.4.11 Pressure/Temperature Curve; dated September 16, 2002

CR 00124037; 50.59 Review Not Completed as Required per CPS 1870.02; dated September 22, 2002

#### Procedures

LS-AA-104; Exelon 50.59 Review Process; Revision 2

LS-AA-104-1000; Exelon 50.59 Resource Manual; Revision 0

LS-AA-104-1001; 50.59 Review Coversheet Form; Revision 0

LS-AA-104-1002; 50.59 Applicability Review Form; Revision 0

LS-AA-104-1006; Exelon 50.59 Training and Qualification; Revision 0

LS-AA-107; UFSAR Update Procedure; Revision 0

## 1R17 Permanent Plant Modifications

### Modifications

31717; Replace Division II DG Crank Lockout Pressure Switches 1PSDG064C and 1PSDG065C with a Model with a Smaller Dead Band; dated November 21, 2001

32181; Remove the ERAT/RAT SVC Freeze Input to The SVC Controller by Jumping the Breaker Aux Contact "B" from the Division 1 Diesel Generator Output Breaker; dated November 21, 2001

330499; Authorization for an Acceptable Replacement for Obsolete Gould ITE Type HE, JL, KM and E2 Molded Case Circuit Breakers Used in Gould ITE 5600 Series 125 VDC Motor Control Center; dated May 9, 2002

331074; Rotate Rosemont Transmitter 1LT-SM016 Suppression Pool Level; Revision 1

331208; Install Ball Valves in the MCR Breathing Air System Fill Lines; Revision 1

331323; Feedwater Support Modification; Revision 0

331896; Replacement of Cylinder Indicator Valves on Div 1 Diesel Generator; Revision 0

333256; Replace the Division III Carbon Steel Vacuum Breakers with New Stainless Steel Replacements (1SX315A/B and 1SX316A/B); Revision 0

333417; Upgrade Woodward Controls 2301A Load Sharing and Speed Control on the Division II Diesel Generator 1B Control Panel (1PL12JB); Revision 1

334569; ODG-ST-11 Line Replacement; Revision 0

335110; Allow Replacement of Existing Reactor Core Isolation Cooling (RI) Piping of Carbon Steel Material with 2 1/4 CR-MO (Chrome-Moly) Material; Revision 0

### Equivalency Evaluations

Evaluation #10718/1106915; Hydrogen Ignitors - The original AC Delco 7G glow plug is obsolete and possesses a high failure rate per CR 2-01-02-143. The Champion CH-78 (Stock # 178) glow plug is an acceptable alternate in fit, form, and function to the original AC Delco 7G.

Evaluation #16231/1146463; Emergency Diesel Generator (EDG) Right Hand Air Start Motors - Evaluation #16231 performed IEE to approve material changes as per equivalency performed by diesel vendor, ESI, and scanned into IEE OLE field. Part number of motors did not change.

### Design Report

DR-A020104; Design Report DR-A020104 Revision 0 for 3/4", stainless steel, ANSI Class 600, In-line Check Valve with Screwed End Endcaps (Purchase order No. PO 00037775; BNL Shop Order No. A020104); Revision 0

### Condition Reports

CR 1-96-11-252; Unauthorized Modification Installed in WS System under MWR D74712 - System Declared Operable; dated November 16, 1996

CR 86825; RR FCV A Temp Mod Implementation Problems; dated December 15, 2001

CR 93284; Discrepancies ID'ed in D C P 32236; dated January 31, 2002

CR 2-01-05-157-0; Inadequate Implementation of LS-AA-104; dated May 15, 2001

CR 00064517; 2-01-07-053 Design Change Process Breakdown for EC 331444 CO; dated July 5, 2001

CR 00099796; FP Diesel Tank Level Changed Without Documentation Bases; dated March 18, 2002

CR 00105636; Design Deficiency in RCIC MOD; dated May 20, 2002

CR 00108356; NON (Nuclear Operations Network) Review of Effects of Diesel Exhaust on Charcoal Filters; completed October 30, 2002

CR 00115251; Non-compliance w/ANSI N18.7 Configuration Changes; completed July 23, 2002

CR 00119318; Enhancements to OP-AA-108-101/102; completed August 26, 2002

CR 00123080; Potential Expiration of TS 3.4.11 Pressure/Temperature Curve; dated September 16, 2002

### Procedures

CI-01.00; Instrument Setpoint Calculation Methodology; Revision 2

CC-AA-102; Design Input and Configuration Change Impact Screening; Revision 4

CC-AA-103; Configuration Change Control; Revision 3

CC-MW-103-1001; Configuration Change Control Guidance; Revision 0

CC-AA-107; Configuration Change Acceptance Testing Criteria; Revision 2

CC-AA-107-1001; Post Modification Acceptance Testing; Revision 0

CC-AA-309; Control of Design Analysis; Revision 3

SM-AA-300; Procurement of Engineering Support; Revision 0

SM-AA-401; Material Procurement; Revision 2

#### Miscellaneous Documents

Assessment of Maintenance Effectiveness 10CFR50.65 (a)(3) Assessment, Clinton Power Station, March 1, 2000 to October 20, 2002

#### Flow Accelerated Corrosion Issues

CSI Calculation No. 01065301; CHECWORKS FAC Analysis - Clinton Power Station; Revision A (For Use); dated January 11, 2002

ER-AA-430; Conduct of Flow Accelerated Corrosion Activities; Revision 0

ER-AA-430-1001; Guidelines for Flow Accelerated Corrosion Activities; Revision 0

ER-AA-430-1002; Feedwater Heater Shell Inspection for Detection of Flow Accelerated Corrosion; Revision 1

### **LIST OF ACRONYMS USED**

ADAMS	Agency-wide Document Access and Management System
CFR	Code of Federal Regulations
DRS	Division of Reactor Safety
EPU	Extended Power Up-rate
FAC	Flow Accelerated Corrosion
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records System
SDP	Significance Determination Process
SER	Safety Evaluate Report
UFSAR	Updated Final Safety Analysis Report

Inspection was rescheduled from July 29, 2002 to December 9, 2002

### **MODIFICATION AND 50.59 INSPECTION DOCUMENT REQUEST**

The following information was provided electronically to the licensee prior to the inspection:  
E-mailed on June 7, 2002

Lead Inspector: Zelig Falevits

Team Members: Gerard O'Dwyer, Ken O'Brien, Bob Winter

#### **I Information Needed for In-Office Preparation Week (July 22-26, 2002)**

The following information is needed by July 19, 2002, or sooner, to facilitate the selection of specific items that will be reviewed during the onsite inspection week. The team will select specific items from the information requested below and submit a list to your staff by July 24, 2002. We request that the specific items selected from the lists be available and ready for review on the first day of onsite inspection (July 29, 2002). If you have any questions regarding this information, please contact me at (630) 829-9717 or e-mail [zxf@nrc.gov](mailto:zxf@nrc.gov) as soon as possible. All lists requested should cover the time frame July 2000 until present. All information should be sent electronically if at all possible.

#### **Permanent Plant Modifications**

1. List of permanent plant modifications/ design changes. In addition to the list, please provide a brief (one paragraph) description of each modification (e.g., copy of modification description from DCP or safety evaluation.)
2. List of setpoint changes. (Identify system and instrument).
3. List of equivalency evaluations or suitability analysis.
4. List of commercial grade dedications.
5. List of condition reports (open or closed) issued to address permanent plant modification issues, concerns, or process.
6. Copy of procedures for the following: modifications, design changes, set point changes, equivalency evaluations or suitability analyses, commercial grade dedications, and post-modification testing.

#### **Changes, Tests, or Experiments (10 CFR 50.59)**

1. List of all 10 CFR 50.59 completed evaluations involving: (A) changes to facility (modifications); (B) procedure revisions; (C) tests or non-routine operating configurations; (D) changes to the UFSAR; or (E) calculations

2. List of all 10 CFR 50.59 screenings that have been screened out as not requiring a full evaluation involving: (A) changes to facility (modifications); (B) procedure revisions; (C) tests or non-routine operating configurations; (D) changes to the UFSAR; or (E) calculations.
3. List of condition reports (open or closed) issued to address problems associated with 10 CFR 50.59 evaluations, screenings, or process.
4. Copy of procedures that specify how 10 CFR 50.59 evaluations and screenings are performed.
5. Copy of procedures that delineate how 10 CFR 50.59 FSAR updates are prepared by engineers or staff and how the licensee submits 10 CFR 50.59 FSAR updates.
6. List of special tests or experiments and non-routine operating configurations in the last two years (if any.)

#### **General Information**

1. Latest engineering organization chart
2. Site phone list
3. System and Design Engineering lists
4. List of maintenance rule high safety significant systems
5. List of maintenance rule (a)(1) systems. (Those systems presently in (a)(1) and systems that were (a)(1) in 2001 or 2002 and returned to (a)(2) [List date system went to (a)(1) and date system returned to (a)(2)])

## **II Information to be Available on First Day of Onsite Inspection**

We request that the following information be available to the inspectors once they arrive onsite. (Copies of the updated final safety analysis report, independent plant evaluation probabilistic safety analysis, vendor manuals, or technical specifications do not need to be solely available to the team as long as the inspectors have ready access to them.)

- The latest 10 CFR 50.59 Final Safety Analysis Report Update Submittal
- Updated Final Safety Analysis Report
- Technical Specifications
- Independent Plant Evaluation Probabilistic Safety Analysis Report

- Vendor Manuals
- Equipment Qualification Binders
- Relevant Calculations And Analyses (for selected modifications and 50.59s)
- Copies of previously selected modifications, permanent plant changes, design changes, setpoint changes, procedure changes, equivalency evaluations, suitability analyses, calculations, commercial grade dedications, 10 CFR 50.59 evaluations and screenings and condition reports.



## PP 7028 FAC INSPECTIONS 2004 REFUELING OUTAGE

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## Engineering Department Work Management Handbook

2003-2004 Program Scope Memo Vermont Yankee -Engineering Department	
WBS Element:	6098
Title:	Piping Flow Accelerated Corrosion (FAG) Inspection Program 2003 & 2004 Efforts
Department:	Design Engineering - Mechanical / Structural
Owner:	James Fitzgibbon
Backup:	Thomas O'Connor
Procedure No. & Title:	pp 7028, Piping Flow Accelerated Corrosion Inspection Program
<p><b>Detailed Scope of Project (explanation):</b> Engineering activities to support ongoing Inspection Program to provide a systematic approach to insure that Flow Accelerated Corrosion (FAC) does not lead to degradation of plant piping systems. Program Procedure PP 7028 controls engineering and inspection activities to predict, detect, monitor, and evaluate pipe wall thinning due to FAC. Activities include modeling of plant piping using the EPRI CHEGWORKS code to predict susceptibility to FAG damage, selection of components for inspection, UT inspections of piping components, evaluation of data, trending, monitoring of industry events and best practices, and recommending future repairs and for replacements prior to component failure.</p>	
<p><b>Expected Benefits (Justification):</b> VY committed to have an effective piping FAG inspection program in response to GL 89-08.</p>	
<p><b>Consequences of Deferral:</b> Possible hazards to plant personnel, Loss of plant availability, unscheduled repairs, and deviation from previous regulatory commitments.</p>	
<p><b>Duration of Program:</b> Life of plant</p>	
<b>Key Deliverables or Milestones:</b>	<b>Completion</b>
Issue 2002 Outage Inspection Report	Estimate 1/22/03
Issue 2004 RFO Outage Inspection Scope per Entergy template (14 months before outage). Including Scoping worksheets.	3/27/03
Update Piping FAG susceptibility screening to account for piping and drawing updates. Include consideration of power uprate & life extension.	6/1/03
Update piping Small bore piping database and FAG screening to account for piping and drawing updates. Include consideration of power uprate & life extension.	7/1/03
Update GHECWORKS models with 2001 & 2002 RFO Inspection data (Note ideally results are to be used in determining the 2004 inspection scope, however schedule milestones override program logic.)	9/1/03

## Engineering Department Work Management Handbook

Key Deliverables or Milestones: - continued		Completion	
Updates to Program Procedures as identified in Self Assessments.		Estimate 6/1/03	
Develop FAC Program Health Report Template ( Format and Performance Indicators) .		7/1/03	
Perform Program Self Assessment (minimum once per cycle). Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry meetings & evaluation of industry events for effects on VY.		10/1/03 12/31/03	
RFO 24 support Issue 2004 Outage Inspection Report		5/1/04 7/15/04	
Update CHECWORKS models with 2004 RFO Inspection data. Issue 2005 RFO Outage Inspection Scope per Entergy template (Approx. 14 months before outage) Including Scoping worksheets.		8/15/04 8/15/04	
Perform Program Self Assessment (minimum once per cycle). Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry meetings & evaluation of industry events for effects on VY		10/1/04 12/31/04	
Estimated Budget or Expenses:		Amount	
Catered in DE Mechanical/Structural Base Budget:		N/A	
Others Impacted By Project:	Support Required? Yes/No	Estimated Hours	Review
2120 - System Engineering	YES	40	
2130 Engineering Support			
2160 Fluid Systems Engineering	YES	40	
2160 Electrical/I&C Engineering			
2160 Mechanical/ Structural Design others:			
Level 3 Forecast: Attached			
Performance Indicator (as applicable) Performance Indicators for FAC Program will be developed in new Program Health Reports Task as defined above.			

# Engineering Department Work Management Handbook

YEAR 2004

Task No.	Task Description	Preparer (HRS) Estimated	Reviewer (HRS) Estimated.	TOTAL (HRS) Estimated.	Est. Start	Est. Delivery f Completion Date
04-1	RFO 24 support	160	80	240	3/15/04	5/1/04
04-2	Issue 2004 Outage Inspection Report. Required within 90 days of startup from 2004 outage	50	30	90	6/11/04	7/15/04
04-3	Update CHECWORKS models with 2004 RFO Inspection data.	120	50	160	6/1/04	8/15/04
04-4	Issue 2005 RFO Outage Inspection Scope per Entergy template (14 months before outage) Including Seoping worksheets.	40	20	50	8/1/04	8/15/04
04-5	Perform Program Self Assessment (minimum once per cycle).	40	20	50	9/1/04	10/1/04
04-1	Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry meetings, evaluation of industry events for effects on VY.	200	50	250	1/01/04	12/31/04
2004			Total Hrs	880		

NEC020182

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# Piping FAC Inspection Program Level 3 Fragnet

Task N.	Task Description	PREP (JCF)	REVIEW (TOe)	TOTAL (Hrs)	Est. Start	Est. Finish	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
03-3	Update Piping FAC susceptibility screening to account for piping and drawing updates. Include consideration of power up "t. & life extension).	150	30	80	14115/03	611/03												
03-4	Update piping Small bore piping database and FAC screening to account for piping and drawing updates. Include consideration of power uprate & life extension).	180	40	1120	5/1103	711/03												
03-5	Update CHECWORKS models with 2001 & 2002 RFO inspection data (Note ideally results are to be used in determining the 2004 inspection scope, however schedule milestones override program logic.)	120	60	180	7/1103	911/03												
03-6	Updates to Program Procedures as identified in Self Assessments. Develop FAC Program Health Report Template (Format and Performance Indicators).	40	20	60	5/1/03	6/1/03												
03-7	Perform Program Self Assessment (minimum once per cycle)	40	120	160	7/1103	10111031												
03-8	Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry meetings, & evaluation of industry events for effects on vy.	160	40	200	1/1103	12/31/03												

NEC020183

ID	Description	Start	Finish	Qty	Float
<b>Erosion Corrosion Program</b>					
6098033	Update Piping FAC Susceptibility Screening - Drwg	15APR03A	02JUN03	34* ME-FITZP,	80.00
6098036	Update to Program Pr edu as identified in SA	01MAY03	02JUN03	22* ME-FITZP, ME-OCONN	60.00
6098037	Update Piping Small Piping Database d FAC	03JUN03	01AUG03	43 ME-FITZP, ME-OCONN	20.00
6098037	Develop FAC Program Health Report Template	02JUN03	01JUL03	22* ME-FITZP, ME-OCONN	30.00
6098038	Update CHECKWORKS Model w/ 2001/2002 RFO	01JUL03	28SEP03	44* ME-FITZP, ME-OCONN	180.00
6098038	Perform Program Self Assessment	01JUL03	01OCT03	50* ME-FITZP, ME-OCONN	60.00
23P8098	Erosion Corrosion Program Maintenance	01NOV03	31DEC03		200.00

6098042	Issue 2004 Outage Inspection Report (90 Day Req)	01JUL04		32* ME-FITZP, ME-OCONN	90.00
6098043	Update CHECKWORKS model w/ 2004 RFO Inspect Data	18JUL04	28SEP04	54 ME-FITZP, ME-OCONN	80.00
6098044	Issue 2005 RFO Outage Inspect Report Entry Temp	20SEP04	4OCT04	1 ME-FITZP, ME-OCONN	60.00
6098045	Perform Program Self Assessment	01SEP04	01OCT04	23* ME-FITZP, ME-OCONN	60.00
24P80	Erosion Corrosion Program Maintenance	02JUN04		207 ME-OCONN, ME-FITZP	250.00

7230A05	Cu and V&V	18JUL03	27AUG03	22 ME-FITZP	0.00
7230A06	SI/VY Historical Baseline	20JUL03	1OCT03	00 ME-FITZP	0.00
7230A06	VY Develop Fatigue Monitoring	1JUL03	28OCT03	75 ME-FITZP	0.00
7230A07	SI Installation Training	1OCT03	0OCT03	11 ME-FITZP	0.00
723008	VY - Fatigue Project Support	02JAN03A	01DEC03	00 ME-FITZP	0.00

Start Date 01JAN08  
 Finish Date 31MAY07  
 Data Date 12MAY03  
 Run Date 10MAY03 14:00



John Dougherty  
 EX 3098  
 VY Engineering Work Control

Inspection Location Worksheets / Methods and Reasons for Component Selection

By:

JCH 3/27/03

Reviewed

TCE 3/29/03

Piping components are selected for inspection during the 2004 refueling outage based on the following groupings and/or criteria.

Large Bore Piping

- LA: Components selected from measured or apparent wear found in previous inspection results.
- LB: Components ranked high for susceptibility from current CHECWORKS evaluation.
- Le: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.
- LD: Components selected to calibrate the CHECWORKS models.
- LE: Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. (through the Systems Engineering Group).
- LF: Engineering Judgment / Other
- LG: Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

Small Bore Piping

- SA: Susceptible piping locations (groups of components) contained in the Small Bore Piping data base which have not received an initial inspection.
- SB: Components selected from measured or apparent wear found in previous inspection results.
- sc: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.
- so: Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. (through the Systems Engineering Group).
- SE: Engineering Judgment / Other.
- SG: Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

Feedwater Heater Shells

NO feedwater heater shell inspections will be performed during the 2004 RFO. Previous plans were to complete the IIT grids on the No. 1 & 2 heaters have been made moot by the decision to replace all 4 HP feedwater heaters for EPU. The shells on all four new heaters will be a Chrome-moly material (P-11). Informational visual inspections of the open ends of Feedwater, Extraction Steam, Heater Drain, Vents and Moisture Separator piping will be performed as access is available.

VY Piping FAG Inspection Program PP 7028 - 2004 Refueling Outage  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

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LA: Large Bore Components selected(Identified) from previous Inspection Results

From the 1995, 1996, 1998, 1999, 2001, 2002, Refueling Outage Inspections (Large Bore Piping) these components were identified as requiring future monitoring. The following components have either yet to be inspected as recommended, or the recommended inspection is in a future outage

Inspect. No.	Loc. SK	Component ID	Notes/Comments / Conclusions
96-13 96-14	001	FD01EL04 FD01SP04	1996 report recommended inclusion of FD01SP04 into 2001 RFO Scope (lower readings at U.S. counterbore). UT inspect elbow and downstream tee in 2004
99-03 99-04	002	FD02.EL01 FD02.TE01	1999 Recommendation to inspect tee in 2002. Component is downstream of pump 18. "B" Pump is used a standby pump, based on usage, inspection was deferred until 2004. UT inspect elbow and downstream tee in 2004
99-25 99-26	00.	FD14EL03 FD14SP03	1999 recommendation to inspect pipe at upstream counterbore in 2004. Given that the only low readings were at the pipe counterbore and that 2004 RFO work includes replacement of both No.1 feedwater heaters located under the elbow. Defer re-inspection of the elbow FD14EL03 & pipe FD14SP03 until the 2005 RFO.
101-03 01-04	001	FD01EL01 FD01TE05	2001 recommendation to inspect the tee in 2004. UT inspect elbow and downstream tee in 2004 (1998 RFO results recommended inspection in 2001) Also add inspection of the reducer upstream of the elbow
02-08 02-09	016	FD18EL01 FD18SP02US	2002 recommendation to inspect the elbow in 2007 based on a single measurement. Re-inspect elbow and downstream pipe in 2007 (3 cycles from 2002).



YY Piping FAC **Inspection** Program. PP 7028 \_ 2004 Refueling Outage  
**Inspection** Location Worksheets I Methods and Reasons for Component Selection

LA: Large Bore Components selected (identified) from previous Inspection Results - continued

Turbine Cross-around Piping:

Previous Internal Visual UT & Repair History:

Line	Mat.	Year Replaced	Internal RF016 81992	Visual =V RF017 F1993	Internal Thickness RF018 81995	RF019 F1996	UT, Re RF020 S1998	Re RF021 F1999	Perfomed =R RF022 82001	RF023 F2002
36"-A	GE**	1983		V	V	V	V			
36"-B	GE**	1981	V	V	V	V	V	V		
36"-e	GE"	1981	V	V	V		V			
36"-D	GE**	1983		V	V		V			
30"-A	P-22"	1985	V		V		V			
30"-B	CS.	Or inal	VIUT/R	VIUTIR-	VIUTIR	V/UT	V	V		V
30"-C	P-22"	1993	VIUT/R							
30"-D	P-22"	1985			V					

" 36' straight pipe sections replaced with GE B50A242E, elbows on the B & C lines are Original GE specification D50A67D, elbows on A & D lines are 050A67E (Tnom = 0.625 inch).

'30" A,B,C replaced with A691 CL22 (2\_114Cr), Fittings A234 WP22. (Tnom. = 0.625 inch)

30' B remains GE B50A2420, fittings and GE 050A670 carbon steel (Tnom = 0.50 inch),

NOTE: **Reference** Dwg. No. 5920-6841 Sh. 1 of 2 **needs to be** updated with **correct** information. This will be performed during the EPU design change effort.

2004 RFO HP turbine work and MS internals/drain line work will have all (4) 36 inch line manways open for access to perform internal visual inspections.

Perform internal visual inspection of all four lines, Priority is A 36" line for access to internals of the 12 inch diameter CS stub piece in extraction steam line. Also if manways and CIV SRVs are removed, perform visual inspection of the 30" C & D lines to confirm condition of P22 replacement materials.

2005 RFO based on increased flows and the possibility of different flow regimes in both the 36 & 30 inch piping, perform a visual inspection. LP turbine work in 2005 RFO may provide opportunity for access to the 30" lines. As a minimum inspect (2) 36 inch lines and the 30" B line.

**VY Piping FAC Inspection Program PP 7028 • 2004 Refueling Outage**  
**Inspection Location Worksheets I Methods and Reasons for Component Selection**

LB: Large Bore Component Ranked High for Susceptibility from CHECWORKS Evaluation

The current CHECWORKS wear rate calculations contain inspection data up to the 1999 RFO and wear rate predictions are current to the 2001 RFO. The 2001 and 2002 RFO inspection data has been entered into the CHECWORKS database. However, updated wear rate calculations are not complete, and won't be in time to support the schedule date for Issuing the inspection scope for the Spring 2004 outage. Based on a review of the 2001 and 2002 RFO inspection data for components on the Feedwater, Condensate, and Heater Drain Systems, the CHECWORKS models still appear to over-predict actual wear. Nothing new or unanticipated was observed in 2002.

Feedwater System

Listed below are components which meet the following criteria:

- a) negative time to Tmin from the predictive CHECWORKS runs which include inspection data up to the 1999 RFO,
- b) no inspections have been performed on these components or the corresponding components in a parallel train since the 1999 RFO.

Component ID	Location Sketch	Location	Notes
FD07EL03	005	T.B Feed Pump Room	No inspection data for corresponding component FD08EL02 in other train. Inspect this or the other train component in 2004. This component will be inspected in 2004.
FD07TE01 FD07EL11	006	T.B Heater Bay Elevs 228 & 248	Components on other train were inspected in 1998. Results indicate minimal wear. After updating the CHECWORKS model with newer data, assess need for additional inspections in 2005 RFO.
FD07EL12	006	T.B Heater Bay Bay, 248	Feedwater heater replacement to occur in 2004 RFO. Perform internal visual inspection at open end on this component.
FD14EL07	009	RX Steam Tunnel El. 266	Internal visual of elbow performed in 1996 during Check valve replacement. no indication of wall loss at that time. Inspect this or the other train component in 2004. Inspect this component in 2004.
FD08EL02	011	T.B Feed Pump Room	No inspection data for corresponding component FD07EL03 in other train. Inspect this or the other train component in 2004. FD07EL03 will be inspected in 2004.
FD08TE01 FD08EL07	012	T.B Heater Bay Elevs 228 & 248	Intermediate components FD08EL06 & FD08SP06 were inspected in 1998. Results indicate minimal wear. After updating CHECWORKS model with newer data, assess need for inspecting components on the train vs. these.
FD08EL08	012	T.B Heater Bay Elev. 248	Feedwater heater replacement to occur in 2004 RFO. Perform internal visual inspection at open end on this component.
FD15EL08	01	RX Steam Tunnel EL 266	Internal visual of elbow performed in 1998 during check valve replacement. no indication of wall loss at that time. After updating CHECWORKS model with newer data, assess need for inspecting this component in 2005 RFO.

**VY Piping FAC Inspection Program PP 71128 - 2004 Refueling Outage**  
**Inspection Location Worksheets I Methods and Reasons for Component Selection**

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LB: Large Bore Components Ranked High for Susceptibility from CHECWORKS Evaluation. continued

Condensate System

Only one component was identified as having a negative time to Tmin. This was CD30TE02DS, the downstream side of a 24x24x20 tee on the condensate header in the feed pump room. The CHECWORKS prediction for the downstream side of the tee has a small negative hrs relative to the remainder of the components in the system and relative to the upstream side of the same tee. Other tees on the same header have been previously inspected and show no significant wear. The CHECWORKS model includes UT data up to the 1999 RFO. The inspections on this system performed in 2001 indicate minimal wear. The 2001 inspection data will be input to CHECWORKS to better calibrate the model.

To inspect the components with the highest susceptibility as ranked by CHECWORKS and to obtain a more complete set of inspection data for the Condensate System inspect additional components between the No.3 feedwater heaters and the feedwater pumps. Inspect CD30TE02 and CD30SP04 in 2004.

Moisture Separator drains & Heater Drain System.

No components identified as having negative times to Tmin. No components were selected for inspection in 2001 or 2002 based on high susceptibility. However future operation under HWC will change dissolved oxygen in system. A separate evaluation has been performed and components were selected for inspection in 2002. See Section LD below.

Extraction Steam System

Three components on this system with negative time to code min. wall. The piping is Chrome-Moly. ES4ATE01 & ES4ATE02, 30 inch diameter tees inside the condenser have negative prediction (-3426Hrs.) for time to min wall. The negative times to Tmin may be conservative based on the modeling techniques used. Refinement of the model of this system is in progress. The negative time to Tmin is most likely a function of lack of inspection data vs. actual wear. Due to external lagging on this piping and the location inside the condenser, no components are selected for external UT inspection in 2004 based on high susceptibility. However, an opportunity to perform an Internal visual inspection of all the Extraction Steam lines inside the condenser during planned LP turbine work in the 2005 RFO may present itself. See Section LF below.

Note the short section of A106 Gr. B straight pipe on line 12'-ES-1A at the connection to the 36 inch A cross around line is not modeled in CHECWORKS. The component material should be included in the next model update.

VY Piping FAC Inspection Program PP 7028 \_ 2004 Refueling Outage  
Inspection Location Worksheets / Methods and Reasons for Component Selection

LC: Large Bore Components Identified by Industry Events/Experience.

Review of FAC related Large Bore Operating Experience (OEI and/or piping failures reported since January 2001

Date	Plant Type	Description & Recommended Actions at VY
4/7/01	Callaway - PWR	Unexpected extent of thinning in feedwater piping (NRC IN 2001-009 & INPO OE12342) Additional components were inspected in the feedwater system in the 0 11 durin the 2002 RFO in res onse to this event.
5/9/01	Grand Gulf-BWR	Pin Hole Leak in 4 inch carbon steel elbow in RHR min flow line. System has low use at VY «2% of time). A review of VY drawings VYI-RHR-Part 14 Sht.111 and VYI-RHR Part 15 Sht.111 show elbows downstream of restriction orifices. Additional research into this event is warranted. Inspections can be performed with the plant operating. Don't include in the scope of 2004 RFO.
11/20/01	Hamoka 1 BWR	Rupture of HPCI/RCI 6 inch steam supply line at a section of pipe to RHR Hx sprays. VY is an older design which does not have this configuration.
9/24/02	IP2 - PWR	Pin hole leak on 26 1/2" cross-under piping (HP to MSR) in vicinity of dog bones at expansion joint under location of weld overlay localized wear under/around a previous weld overlay repair. VY has solid piping (no expansion joints. Visual inspections of CAR piping will be performed in 2004.
11/2/02	Point Lepreau-PHWR	Failure of Extraction Steam Bellows from LP turbine. VY bellows are made from stainless steel. Primary causes of past failures have been cracking of convolutions and vibration failures of tie rods. The bellows were replaced in 1995 and should not be susceptible to FAC damage.
11/15/02 CHUG Meeting	Summit 1-PWR	Leak in 8 inch Condenser drain header for 3 1/4" pt. FDW Heat exchangers. Also thinning in Gland steam Piping inside the condenser and the 12" Condenser Drain header from MS Drain trap lines. The only large bore drain collector VY is the 8 inch diameter low point drain header. Inspect sections of this line during the 2004 RFO.
1/15/02 CHUG Meeting	Cooper BWR	Thinning found in two 20 inch diameter exit nozzles off LP turbine for extraction steam piping. (VY has replaced all LP turbine stub pieces upstream of the expansion bellows with P-11 material. No actions are required at this time.
6/02 CHUG Meeting,	Oconee 1	Wear found in Heater Drain piping downstream of block valve. Ops was using the gate valve to control flow. All valves on VY HD system are control valves. Normal flow downstream of valves is directly into the feedwater heaters. Bypass valve discharge directly into condenser. TPM monitors possible leakage past the Bypass valves.
6/24/02	Prairie Island 1 - PWR	Preliminary notice of possible extraction steam line piping/bellows failure inside condenser. (See 1/2/02 Point Lepreau notice above).
8/29/02	Turkey Point 3-PWR	Failure of a 6x10 Schedule 40 carbon steel expander in Heater Drain System downstream of a level control valve. Same valve on other train was replaced. However, no inspections were performed on this valve (from INPO Event 250-020829-1, DE 14866. & Info at 11/03 CHUG Meeting). Location is similar to millstone 2 & 3 events in 1991/92. Piping on HD system at VY OS of normal level control valves is constructed from FAG resistant materials or planned for replacement with new Feedwater Heaters. No actions are required for this OE.
10/19/02	Clinton -BWR	Interconnecting piping (4 and 6 inch diameter) between RWCU Heat Exchanger not included in FAC program. Plant assumed they were equipment when in fact they are piping. VY has replaced the original 3 Perflex Hx design with a U-tube Hx. RWCU piping in this area is stainless steel. Therefore not an immediate concern.

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VY Piping fAC Inspection Program PP 7028 \_ **2004** Refueling Outage  
Inspection **Location** Worksheets / Methods and Reasons for Component Selection

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**LD: Large Bore Components Selected to Calibrate CHECWORKS**

The CHECWORKS models have been upgraded to include the 96, 98, & 99 RFO inspection data. The 2001 and 2002 inspection data has been loaded however wear rate analyses are not complete at this time. In 2001 components on the higher temperature end of the Condensate System were inspected to calibrate the CHECWORKS models. The inspection data indicate minimal wear and should reinforce the assessment of low wear in the Condensate System. Additional components selected for inspection in 2004 in Section LB above will be used to calibrate the CHECWORKS model.

Prior to the 2002 there was limited inspection data for the Heater Drain system. The current CHECWORKS models (Pass 1 and some Pass 2) indicate low wear rates. During 2002 a number of new inspections were performed to obtain base line data prior to operation under GE Noble Metals HWC. NO additional components on the Heater Drain system will be inspected in 2004.

**LE: Large Bore Components subjected to off normal flow conditions identified by turbine performance monitoring system (Systems Engineering Group).**

The Systems Engineering Production Variance Reports for 2002 & since startup from 2002 (RF023) do not identify any leaking valves. No other leaking valves or steam traps have been identified (to date) using the Turbine Performance Monitoring (TPM) system. No components will be scheduled for the 2004 RFO based on the TPM reports to date. However, if new data indicates leaking valves then, additions to the outage scope may be required.

**LF: Engineering Judgment / Other**

Nine ASME Section XI Class 1 Category B-J welds are to be inspected by the FAC program per Code Case N-560 in lieu of a Section XI volumetric weld inspection. The VY ISI Program Interval 4 schedule for inspection of these welds is as follows:

Refueling Outage	Section XI ISI Program Weld ID	Description	FAC Program Components
Spring 2004 (RF024) Interval 4 Period 1, Outage 1.	FW19-F3B FW19-F3C FW19-F4 FW21-F1	upstream pipe to tee tee to reducer reducer to pipe tee to pipe	"A" Feedwater on Sketch 010 FD19TE01 FD19RD01 FD19SP04 FD21SP01
Fall 2011 (RF029) Interval 4 Period 3, Outage S,	FW18-3A FW20-3A FW20-F1 FW20-F1B FW18-F4	upstream pipe to tee tee to reducer reducer to pipe horizontal pipe to pipe tee to pipe	"B" Feedwater on Sketch 016 FD18TE01 FD20RD01 FD20SP01 FD18SP04

LF: Engineering Judgment | Other – continued

All Extraction Steam piping is A335-P11, a 1-114 chrome material, except for a short carbon steel stub piece in line 12" ES-1A at the connection to the 36" A cross around line. Internal visual inspection of this stub piece will be performed along with the 36" A cross around line. This extraction steam line (6<sup>th</sup> point extraction) has the highest quality steam of all extraction lines which indicates a relatively lower wear rate. Based on the 1996 inspection data for the carbon steel section, ES1ASP01 (inspection 96-07A) showing a small area of wall thickness less than 0.875 x nominal thickness, the expected changes in flow regime due to power uprate, and that this is the only carbon steel section in the ES system, a repeat inspection to confirm actual wall thickness and also to obtain a baseline thickness prior to power uprate should be performed. Perform external UT inspection of ES1ASP01 in RF024.

Extraction Steam piping in the condenser has external lagging which requires significant effort for removal when performing external visual inspections (plus there are significant staging costs). The piping is A335-P11. However an opportunity to perform an internal visual inspection of all the Extraction Steam lines inside the condenser during planned LP turbine work in the 2005 RFO may present itself.

LG: Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

Word searches of open work orders on EMPAC were performed for the following keywords: trap, leak, valve, replace, repair, erosion, corrosion, steam, FAG, wear, hole, drain, and inspect. No previously unidentified components or piping were identified as requiring monitoring during the Spring 2004 RFO.

VY Piping FAC Inspection Program PP 7028 - 2004 Refueling Outage  
**Inspection Location Worksheets / Methods and Reasons for Component Selection**

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Small Bore Piping

**SA: Susceptible** piping locations (groups of components) contained in the Small Bore Piping data base which have not received an Initial inspection.

Locations on the continuous FDW heater vents to the condenser On the No.3 heaters were inspected in 2002. The continuous vents on the No.4 heater were installed new in 1995. The start up vents operate less than 2% of operating time. No wear was found in previous inspections on Heater Vent piping from the No.1 & 2 heaters. Given that and the lower pressure in the No.4. shells a complete inspection of the remainder of the NO.4 heater vant piping can be deferred. The existing small bore data base and the piping susceptibility analysis is under revision. No additional components from Revision 1 of the data base will be inspected.

**SB: Components selected** from measured or apparent wear found in previous Inspection results.

Small Bore Point No. 20. 2-112" MSD-8 @ connection to condenser A at Nozzle 33 (Inspection No. 98-SB01 identified a low reading at weld on stUb to condenser). Upstream valves are normally closed. TPM system does not indicate any abnormal flow. No inspections will be performed on this line in 2004.

A through wall leak in the turbine bypass valve chest 1<sup>st</sup> seal leak-off line from the No.1 bypass valves occurred in 2003. (ER 2003-044) A temporary leak enclosure has been installed (T.M.2003-002 to contain the leak). W.O. 03-0364 was written to inspect/repair/replace line. The line should be completely replaced with chrome-moly piping. (Dresden has already done this) Given the amount of work already scheduled for the heater bay during the 2004 RFO a complete replacement will be deferred. A local code repair of the piping will be performed to remove the temporary solution (if license renewal is pursued) Should include replacement the entire line With chrome-moly material.

S Item 2" 1SLBPV	Description 2 inch header off the turbine bypass valve chest first seal leak-off connections. Inspect five locations on this line. include the 1/2 line at the No.2 valve. It has the next highest usage from the no.1 valve.	Inspection No. 2004 5B01 to 5805
2-112" ISPL2	HP Turbine pocket drains. inspect first two elbows and connecting piping under turbine based on readings from 1993 inspections 93-5849 to 93-SB52)	20045B06 & 5807

**VY Piping FAC Inspection Program PP 7028 - 2004 Refueling Outage**  
**Inspection Location Worksheets' Methods and Reasons for Component Selection**

**Small Bore Piping**

se: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.

Date	Plant - Type	Description & Recommended Actions at VY
11/23/98	Calvert Cliffs 2 - PWR	Rupture of a moisture separator re-heater (MSR) 2 inch vent line (INPO Event 318-980123-1) No MSRs at VY, therefore no equivalent line at VY.
11/10/98	Hamoka 2 - BWR	Leak due to FAC in turbine driven feed pump casing drain line No turbine driven feed pump at VY, therefore no equivalent line at VY.
4/29/99	Darlington 1 - PHWR	Severed line at steam trap discharge pipe at threaded connection. Equivalent to HHS system at VY. (INPO Event 931-990429-1) Threaded connections typically on condensate side of HHS piping. Lower energy/consequence of leak. Consider during next update of the Small bore data base.
5/10/99	Darlington 4 - PHWR	Leak On HP Feedwater Heater Vent Line downstream of orifice (INPO Event 934-990507-1). At VY inspections have performed OS of orifices on HV lines.
6/14/99	Darlington 2 - PHWR	Leak on steam trap discharge pipe at threaded connection. Equivalent to HHS system at VY. INPO Event 932-990614-1) Same as above.
10/10/99	Darlington 2 - PHWR	Leak on Feedwater Heater Vent Line downstream of orifice (INPO Event 932-991007-1). At VY inspections have performed OS of orifices on HV lines.
10/1/00	Oconee3 - PWR	From 1/2001 CHUG Meeting. MSR Scavenging steam line Pinhole leak in 1" line downstream of flow control valve. No equivalent system at VY.
1/8/01	Oyster Creek - BWR	Rupture of 2 inch line connecting controller/transmitter level column to re-heater drain tank. No MSRs at VY, therefore no equivalent line at VY.
9/1/01	Peach Bottom 3 - BWR	(From 1/14/02 CHUG Meeting), leak on 1 inch Sch. 80 line from in Off Gas Re-combiner pre-heater drain line to condenser. Additional review of AOG steam supply system is required. Consider during next update of the Small bore database.
6/22/01	Pilgrim - BWR	Leak on 2 inch feedwater heater ventline (OE discussed at 1/02 CHUG Meeting). Equivalent lines at VY have been inspected.
10/22/01	St. Lucie 1 - PWR	(From 1/14/02 CHUG Meeting), Leak on 1 inch Sch. 80 normally isolated drain line remote from process system. TPM used to determine leaks from N.C. valves.
11/28/01	Browns Ferry 3 - BWR	Through - wall leaks in drain lines from extraction steam non-return check valves back to condenser. (Similar lines at VY are chrome-moly and there have been previous inspections performed on these lines. No additional inspections are required.
11/15/02 CHUG Mtg.	Halch 1/2 - BWR	Condenser in leakage due to through wall erosion (external?) of 1-112 inch "slop" drains lines inside the condenser. Lines in each unit were cut and capped. Similar events at Byron Unit 11 (OE 12609) and Columbia (OE12145). Limerick & Dresden. VY slop drain lines do not show up on VY P&IDs.
1/15/02 CHUG Mtg.	Catawba 2 - PWR	Leak in HP turbine pocket shell drain 1 inch dia. OEM showed pipe as P-11. However, A-106 Gr. B was installed. Inspections will be performed on this line in 2004 10 base line condition prior to HP turbine rotor replacement.
1/15/02 CHUG Mtg.	Columbia - BWR	Leak in 2 inch drain line from bleed steam trap to condenser. At VY SB piping OS of steam traps is included in the small bore data base.
1/15/02 CHUG Mtg.	Peach Bottom 2 - BWR	Pin Hole leaks in 1" schedule 160 HPCI Steam Supply drains (Plant thought piping was replaced with P-11, However field conditions showed that it was not. Pin at VY inspected in 1999 (99-SB01 to 99-SB03)

continued



VY Piping FAC Inspection Program PP 7028 - 2004 Refueling Outage  
Inspection Location Worksheets 1 Methods and Reasons for Component Selection

**Small Bore Piping**

SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG - continued.

Date	Plant Type	Description & Recommended Actions at VY
11/15/02 CHUG Mtg.	Dresden 2 WR	Thinning found in Bypass valve leak-off line to the 7 stage extraction steam line. Line is 2" Sch. 80, GE B4A39B. Lowest reading was 0.070- found using Phosphor Plate radiography. Line was replaced with A335 P-11. Same line as recent VY through wall leak, RFO 2M41 inspect locally, then long term replacement with A335-P11.
6/02 CHUG Mtg.	AN01 & ANO 2 PWR	Leaks in Gland seal steam to No.3 bearing 1-114 vendor supplied line, Leak in 1" Sch.80 drain from Reheat 2 <sup>nd</sup> stage drain tank to condenser. Additional review of GE supplied steam seal & drains is required. Consider during next update of the Small bore data base.
6/02 CHUG Mtg.	Brunswick 1 - WR	Replaced continuous vent lines on #4 feedwater heaters with chrome-moly pipe. (Smart move for long term.) New vent lines on No.1 & 2 FDW heaters at VY will be chrome-moly.
6/02 CHUG Mtg.	Calvert Cliffs 1 PWR	Pin hole leak in 3/4 inch Sch. 80 drain line off MS supply to steam generator feed 100ma just downstream of orifice. No steam driven feed pumps at VY.
6/02 CHUG Mtg	Fennel 2 - BWR	Leak in first elbow downstream of AOV in 1/112" continuous vent from Turbine Bypass Valve seal drain to condenser. Valve has travel stop which prevents complete closure. Fennel has no steam traps, AOVs are used instead. Piping DS of steam traps on MSD lines are included in the SB program. The only continuous opening to the condenser at VY is the steam leads drains through RO 60-1. This orifice has been replaced with chrome-moly orifice.
1/03 CHUG Meeting.	JAF -BWR	Through wall leaks in 2" Sch. 80 C.S. lines from 5 /6 extraction drain lines immediately downstream of restricting orifices. At VY the only drain lines on the action steam piping are upstream of the reverse截止 valves. There are no restriction orifices at VY. The piping is chrome-moly.
1/03 CHUG Meeting.	Turkey PtA- PWR	Leak in HP turbine bowl drain, 1" sch 60 C.S. pipe. OEM recommended replacement with SS pipe in 1982, did not occur. Equivalent line at VY will be inspected in 2004 to baseline thickness prior to HP turbine rotor replacement.

SD: Components subjected to off normal flow conditions, as indicated from the turbine performance monitoring system (Systems Engineering Group).

No small bore lines have been identified by Systems Engineering on or before 2/27/2003

SE: Engineering judgment

(None at this time.)

ISG: Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

See LG above. The EMPAC search performed in LG above is applicable to both Large and Small components.

(17)

ATTACHMENT 10 (P410F2)  
2004 SCOTLY WORK SHEET.

OIE/POOL GROUP  
INFORMATION.

- The meeting then split into breakout sessions. Aaron Kelley led a session on BWR issues. The following discussions were noted:

#### FAC Problem Areas

Hatch has had lots of wear and repairs to their 8<sup>th</sup> stage extraction (1<sup>st</sup> highest), even though the heat balance diagram shows it to be 99% steam.

CHROMIS  
MOLY @ VY

LaSalle is wondering if there may be problems in their carbon steel turbine nozzles to extraction steam. Riverbend has had to inspect these locations from the turbine side because of the shields.

Quad Cities has had lots of problems in their expansion bellows.

Riverbend replaced the extraction steam check valves using chrome moly. Unfortunately, the internals were carbon steel and they had problems after only two cycles.

SSNO  
POMISE

LaSalle had a failure caused by droplet impingement in a heater vent line 17' downstream of the valve.

LaSalle is experiencing impingement damage in an 8" common drain header to condenser that collects six 10 eight 2" and smaller diameter lines. Stainless will help, but they still will need to inspect.

INSPECT  
8-4509  
IN 2004

Hope Creek has seen a lot of damage in the drain to condenser of the steam to reactor feed pump turbines.

#### Water Chemistry

Riverbend experienced significant increases to iron transport after applying hydrogen injection (medium level of injection). GE did a mini-test.

\* MAXON  
Fe

Nine Mile Point had unexpected failures on the lower end of the heater drains after applying HWe.

LaSalle measured oxygen on the heater drains, and then used the data to revise the CHECWORKS model. The data caused to LCFs on the MSR drains, 1<sup>st</sup> stage reheaters, and 2<sup>nd</sup> stage reheaters to skyrocket.

Columbia River has tentatively concluded that noble metals does not effect the fuel. It is too soon to see if hydrogen water chemistry affects the FAC rates.

#### RPV BoUom Head Drain

LaSalle has not inspected the first elbow low the vessel because of its inaccessibility and high radiation dose involved. For this reason, they selected the second 90" elbow which is outside the vessel pedestal. Results were provided on FACNet. Additionally, the sump will maintain water level if there is a break at the first elbow.

It was noted that it may be possible to inspect the nominally inaccessible areas when there is a 10% disassembly to replace some blades.

LaSalle and Clinton plan to inspect the accessible portions of the line.

Columbia River has inspected several locations on the line. No wear was found. Three inspections were also performed on the RWCU near the drywell. No damage was found.

Exelon (Harold Crockett) volunteered to collate and publish a summary of industry inspections on the line.

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### Inspection Methods.

LaSalle is performing some pre-outage RTs in selective areas due to final feedwater temperature reduction. This is the second time that some pre-outage work was done in nonnally high radiation areas. Aaron Kelly can be contacted for more information. Riverbend is training their QC inspectors to perform VT.

### Power Upgrades.

Nine Mile Point saw little change to wear rates after a 7% uprate. Dresden and Quad Cities did a 15% uprate. Some lines saw increases to wear rates of up to 30%. Temperature changes are believed to be responsible. Perry did a pre-power uprate analysis on the effects to FAC. They used the results to justify line replacements as part of the planning process. LaSalle found no changes to their susceptible-not-modeled rankings as a result of their uprate.

### Life Extension.

General comment was that the NRE has emphasized compliance with NSAG202L-R1 and brought up main steam susceptibility as part of their approval process. At Nine Mile Point, the NRC brought up service water issues. Southern Nuclear is taking credit for other programs in response to the NRC questions on valves.

With the BWR session, Jeff Horowitz led the PWR Breakout Session. The session was broken down into three parts:

A description of very high levels of iron transport experience at an Oquofre. This presentation includes the investigation into the phenomenon, a description of the deposits found, several possible explanations for the deposits, and what the effects of the deposit were on plant performance. A status report on the EDF hydrazine testing program. Unfortunately, no progress has been made since the last report in January to number of problems. The latest problem, inadequate water quality, has been resolved and testing resumed earlier this month. The testing program is expected to take all year to complete. Details of the test program have been presented at previous CHUG meetings. There was also a brief discussion of feedwater oxygen and FAC. Several PWRs are now allowing entry of small amounts of oxygen into the condensate system in hopes of reducing the iron transport. The potential for change to the PWR Water Chemistry Guidelines in this area was discussed.

- Tina Gaudreau discussed several EPRI chemistry projects that have FAC implications. The first was the EDF testing of the effects of hydrazine and oxygen on FAC as summarized by Jeff Horowitz in the PWR breakout session. The second project was the next revision to the PWR Secondary Chemistry Guidelines, that will begin this spring. The third project is an investigation into the influence of dissolved iron, electrochemistry, and chemical parameters on



CHRONO FILE COPY.

Vermont Yankee Nuclear Power Station  
Design Engineering Department" Mechanical/Structural

To S.D. Goodwin

Date March 27, 2003

From J.E. Fitzpatrick

File # VYM 2003/009

Subject Piping FAC Inspection Scope for the 2004 Refueling Outage

## REFERENCES

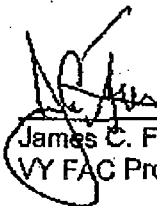
- (a) PP 7028 Piping Flow Accelerated Corrosion Inspection Program, LPG 1 12/06/01.
- (b) V.Y. Piping F.A.C. Inspection Program - 1996 Refueling Outage Inspection Report, March 23, 1999.
- (c) V.Y. Piping FAC Inspection Program - 1998 Refueling Outage Inspection Report, April 2, 1999.
- (d) V.Y. Piping FAG. Inspection Program - 1999 Refueling Outage Inspection Report, February 11, 2000.
- (e) V.Y. Piping FAG, Inspection Program - 2001 Refueling Outage Inspection Report, August 11, 2001.
- (f) V.Y. Piping FAC Inspection Program - 2002 Refueling Outage Inspection Report, January 20, 2003.

## DISCUSSION

Attached please find the Piping FAC Inspection Scope for the 2004 Refueling Outage. The scope includes locations identified using: previous inspection results, the CHECWORKS models, Industry and plant operating experience, input from the Turbine Performance Monitoring System, the CHECWORKS study performed to postulate affects of Hydrogen Water Chemistry operation on FAC wear rates in plant piping, postulated power uprate effects, and engineering judgment.

The planned 2004 RFO Inspection scope consists of 26 large bore components at 11 locations, internal inspection of 6 of the Bilines of the turbine cross around piping, and 11 sections of small bore piping. Given that it's a full year from the start of the outage, any Industry or plant events that occur in the interim or new information may necessitate an increase in the planned scope.

I am available to support planning and inspections as necessary. If you have any questions or need additional information please contact me.

  
James C. Fitzpatrick  
VY FAC Program Coordinator

ATTACHMENT: 2004 RFO FAC Inspection Scope (4 Pgs.)

CC D.Girrolle (Code Programs Supervisor)  
D.King (ISI Program Engineer)  
T.MO'Connor (Design Engineering)  
M.LeFrancois (Systems Engineering)

## LARGE BORE PIPING: External UT Inspections

Point No.	Component 10	Location Sketch	Location	Previous Inspections	Reason / Comments / Notes
2004-01	FD01RDOI	001	T.B. FPR. Elev. 232.	2001	2001 recommendation for repeat inspection of FD01TE05.
2004-02	FO01EL01	001	" " "	2001	
2004-03	FDQ1TEOS	001	" " "	2001	
2004-04	FD01EL04	001	T.B. FPR Elev. 241.	1996	1996 recommendation for repeat inspection of FDQ1SP04.
2004-05	FD01SP04	001	" " "	1996	
2004-06	FD02RDOI	002	T.B. FPR. Elev. 232.	1999	1999 recommendation for repeat inspection of FDOZTE01,
2004-07	FD02EL01	002	" " "	1999	
2004-08	FD02TE01	002	" " "	1999	
2004-09	FD03SP01	003	T.B. FPR. Elev. 232.	NO	Ranked high by CHECWORKS.
2004-10	FD07SP02DS	005	T.B. FPR. Elev. 232.	NO	Ranked high by CHECWORKS include minimum of 36 inch of vertical run upstream of elbow.
2004-11	FD07EL03	005	" " "	NO	
2004-12	FD14SP08DS	009	Stm Tunnel Elev. 266	NO	Ranked high by CHECWORKS include minimum of 32 inch of vertical run upstream of elbow.
2004-13	FD14EL07	009	" " "	NO	
2004-14	FD19TE01	010	Rx <u>Drywell</u> Elev. <u>270</u>	1999	Required Inspections per ASME Section XI ISI Program FAC inspections per ASME Code Case N-560.
2004-15	FD19RD01	010	" " "	1999	
2004-16	FD19SP04	010	" " "	1999	
2004-17	FD21SPOI	010	" " "	1999	

NEC020199

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## LARGE BORE PIPING: External UT Inspections - continued

Point No.	Component 10	Location Sketch	Location	Previous Inspections	Reason / Comments / Notes
2004-18	CD30TE02	036	T.B. FPR EI v.243.	NO	Ranked high by CHECWORKS include 12 inch long stub between CD32LE01 & CD32EL02.
2004-19	CD30SP04	036	" " "	NO	
2004-20	CD32EI01	039	" " "	NO	
2004-21	CD32EL02	039	" " "	NO	
2004-22	ES1ASP01	063	T.B. HB Elev. 255.	1998	Highly susceptible to FAC damage. This is the only remaining carbon steel section in Extraction Steam system. Baseline data for power urate.
2004-23	MSD9TE01 thru MSD9TE08	097	T.B. HB Elev. 249.	NO	Industry Experience with numerous through wall leaks in drain collector headers. Scan as much of header below drains from LeV 38A to 380 and ST-6D-2A to 20 as accessible. See Note 3.
2004-24	MSD9EL05	097	T.B. HB Elev. 237.	NO	Industry Experience with numerous through wall leaks in drain collector headers. Inspect a minimum of 16 inch length on MSD9SP06US - See Note 3.
2004-25	MSD9EL06	097	" " "	NO	
2004-26	MSD9SP06US	097	" " "	NO	

## LARGE BORE UT NOTES:

1. Coordinate minimum extent of insulation to be removed with J.Fitzpatrick or T.M. O'Connor from DE-MIS.
2. A "No" in the previous inspection column indicates asbestos abatement may be required.
3. Piping is part of the proposed ALT Boundary/or Power Uprate AST.

NEC020200

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T to  
ATTACHMENT 10 VYM20031009

VERMONT YANKEE PIPING FAC INSPECTION PROGRAM 2004 INSPECTION SCOPE (3/27/03) Page 3 014

**LARGE BORE PIPING: Internal Visual Inspections (with supplemental UT as required)**

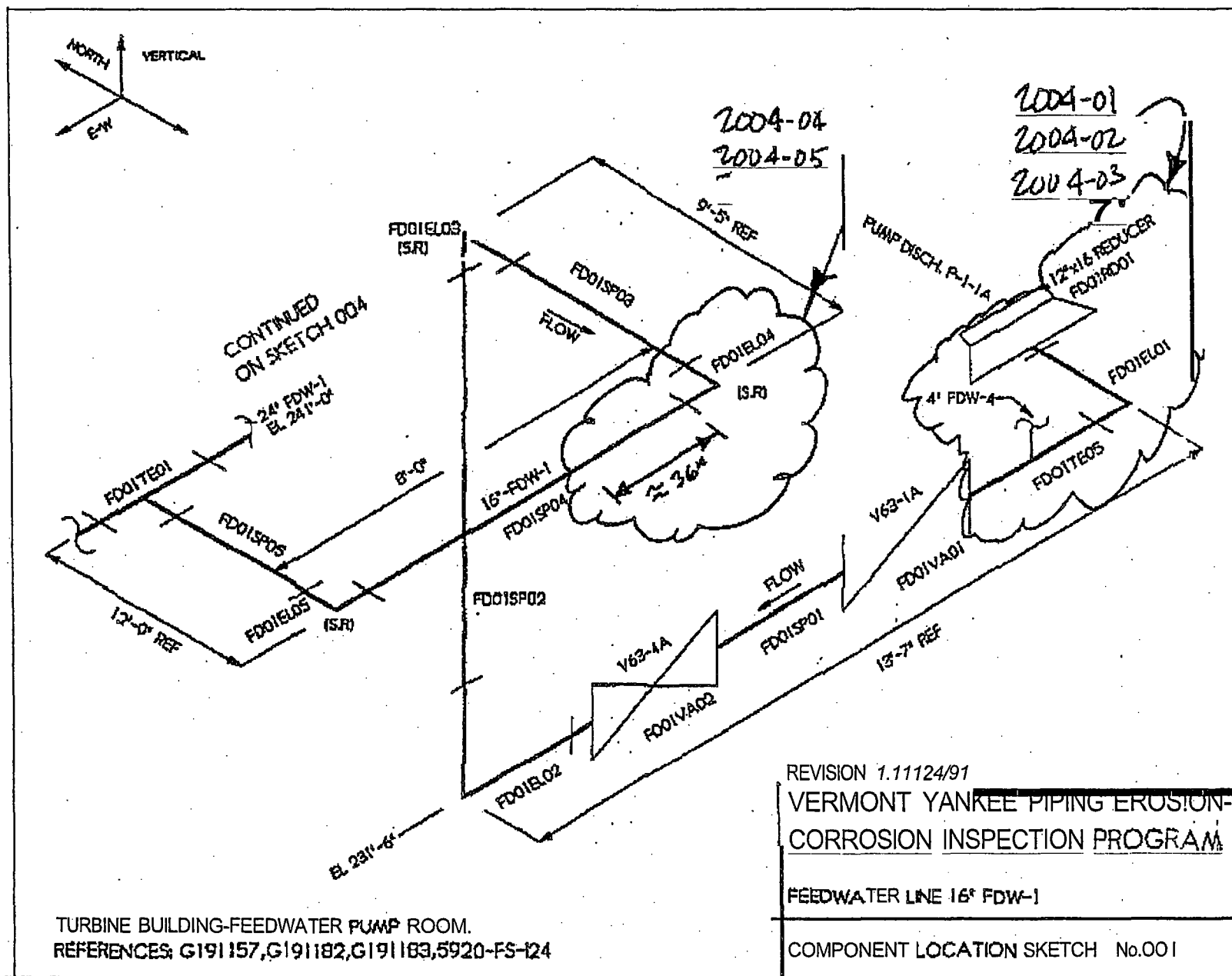
Ins action Point No.	Description
2004-27	"A" 36 inch diameter Turbine Cross Around line (CAR).
2004-28	"B" 36 inch diameter Turbine Cross Around line (CAR).
2004-29	"C" 36 inch diameter Turbine Cross Around line (CAR).
2004-30	"D" 36 inch diameter Turbine Cross Around line (CAR).
2004-31	"E" 30 inch diameter Turbine Cross Around line (CAR).
2004-32	"F" 30 inch diameter Turbine Cross Around line (CAR).

Note: Internal visual inspections of open ends at all large bore connections to the new High Pressure feedwater heaters will be performed during installation of the new heaters during the 2004 RFO. (This includes Feedwater, Extraction Steam, Moisture Separator Drains, and Heater Drain piping.)

NEC020201

123

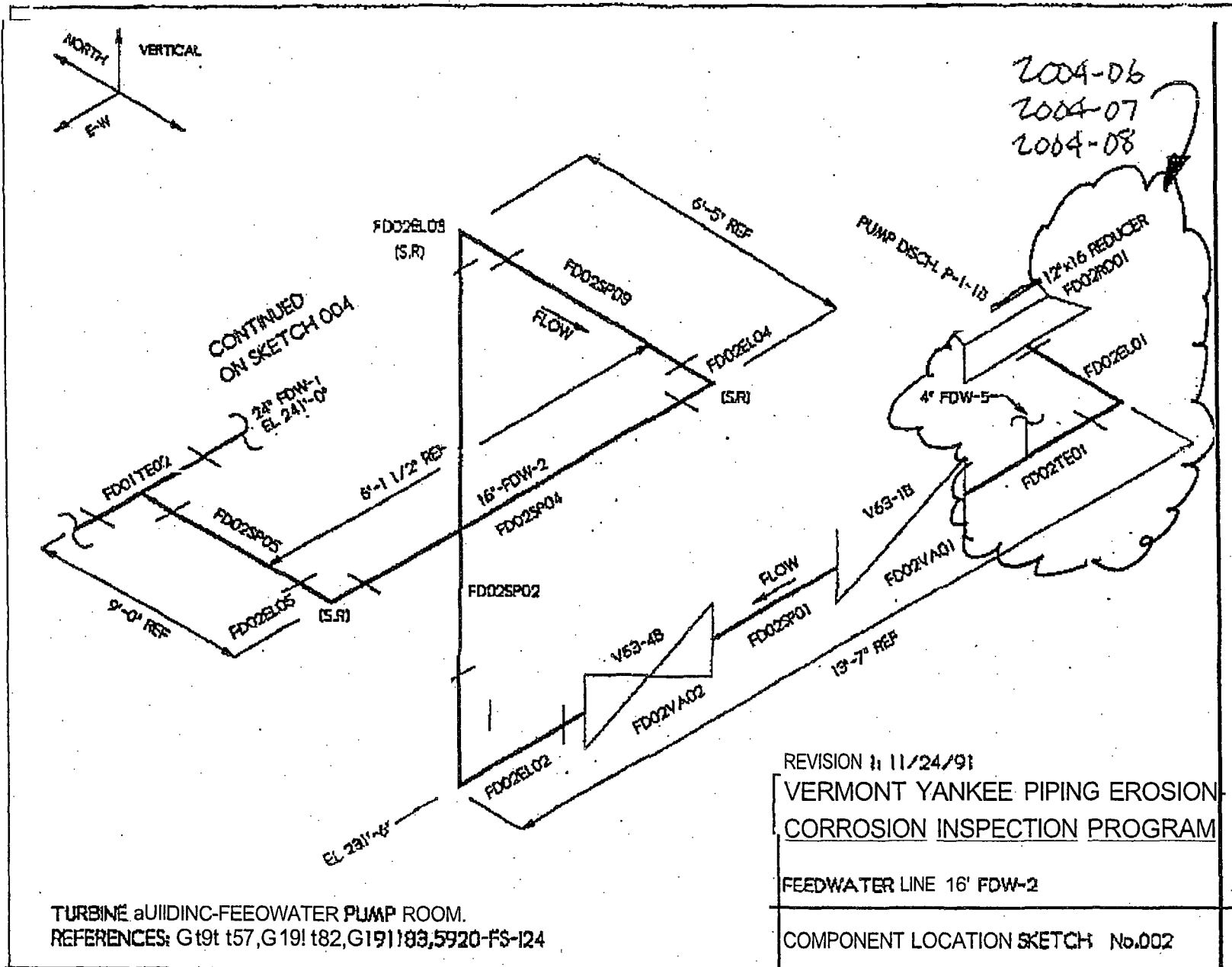
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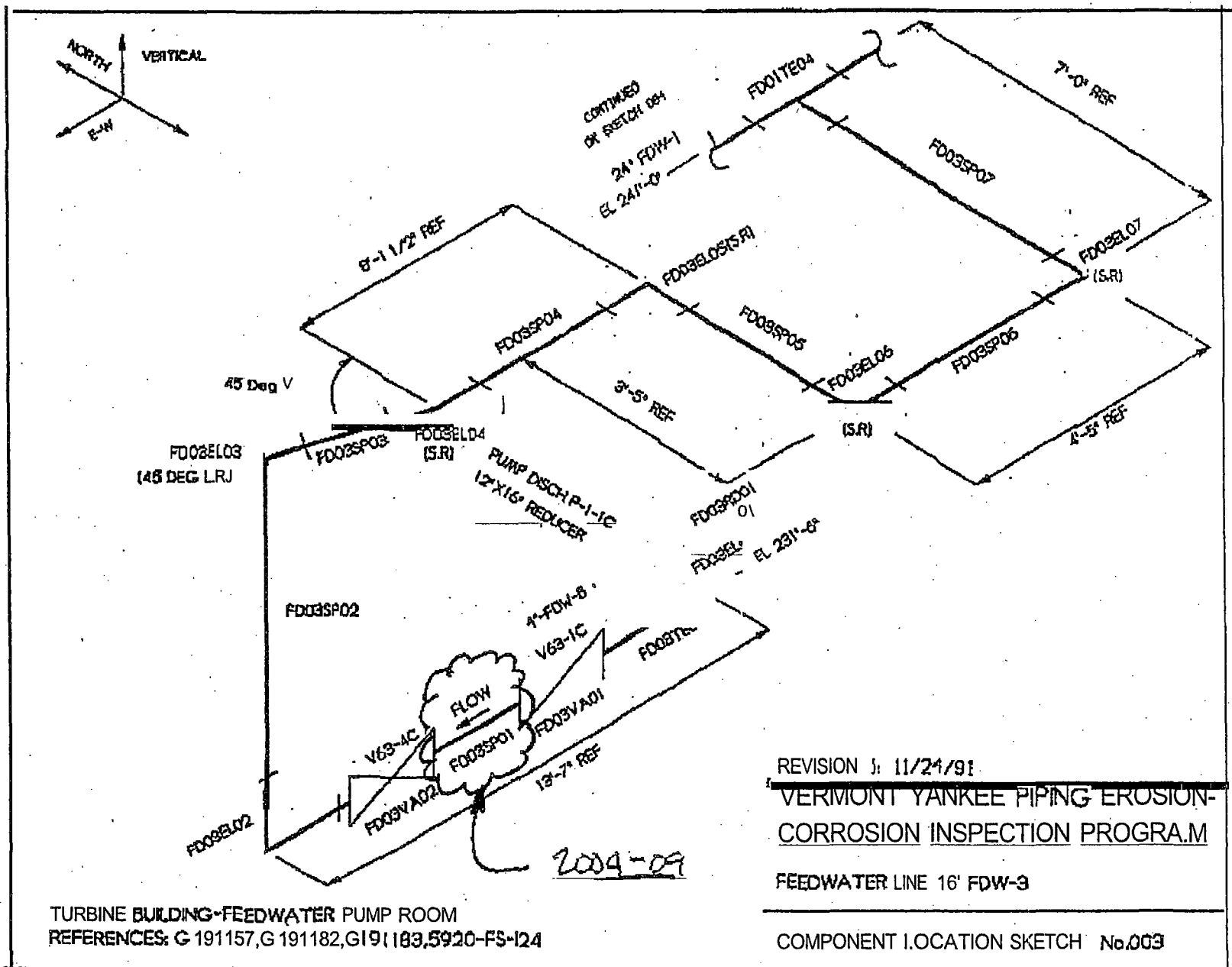
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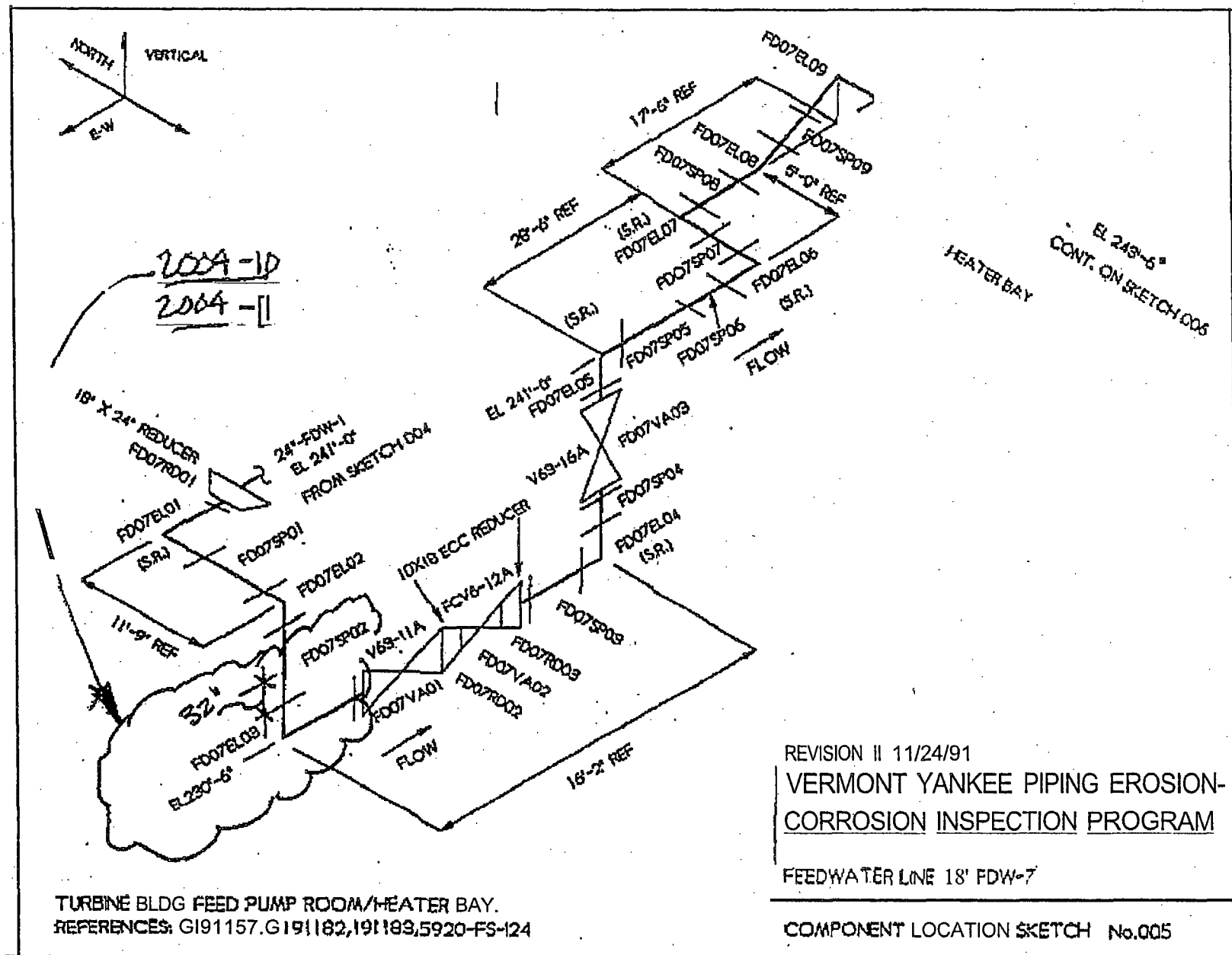
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NEC020204

26

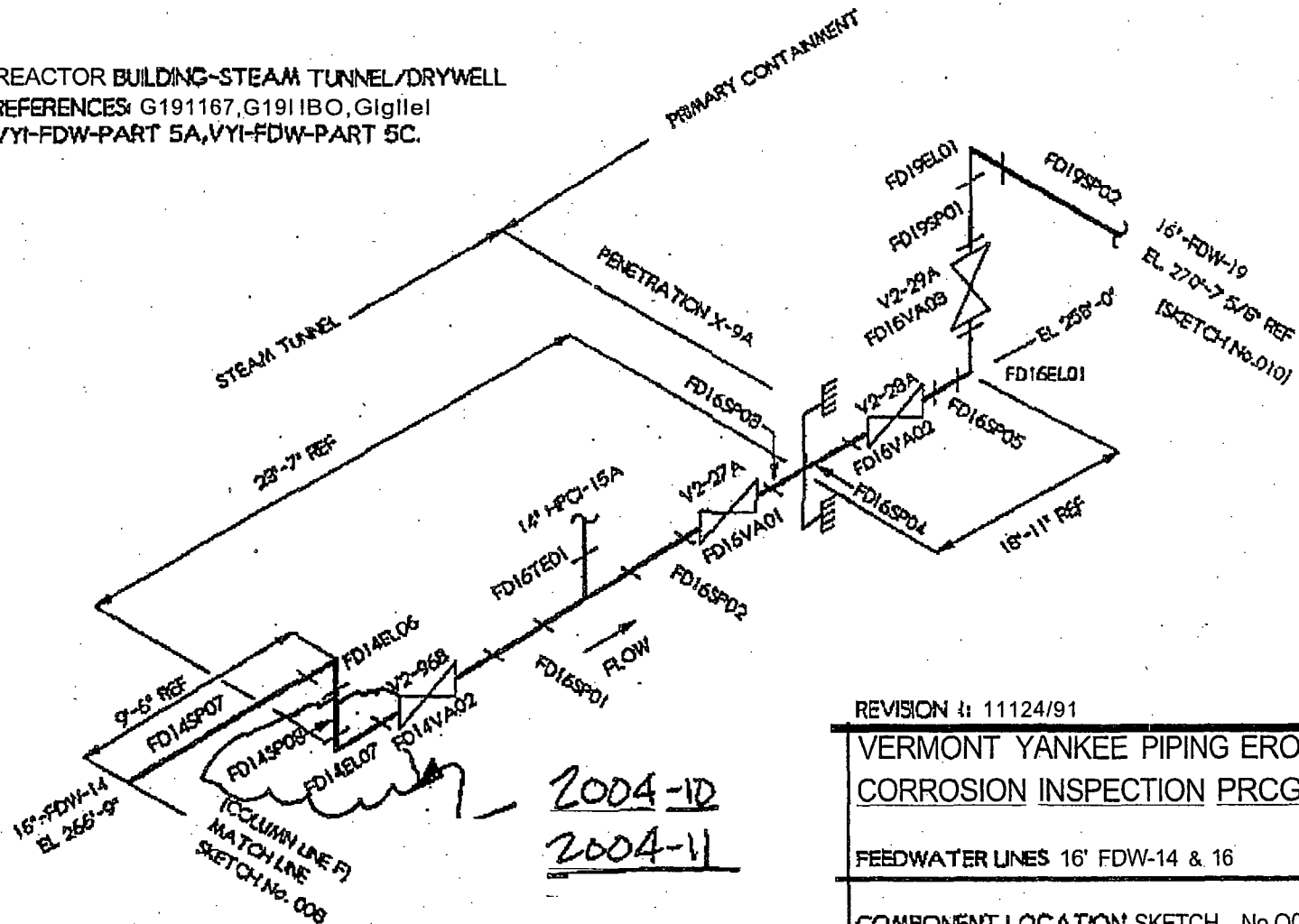




NEC020206



REACTOR BUILDING-STEAM TUNNEL/DRYWELL  
REFERENCES: G191167, G191180, G191181  
VYI-FDW-PART 5A, VYI-FDW-PART 5C.

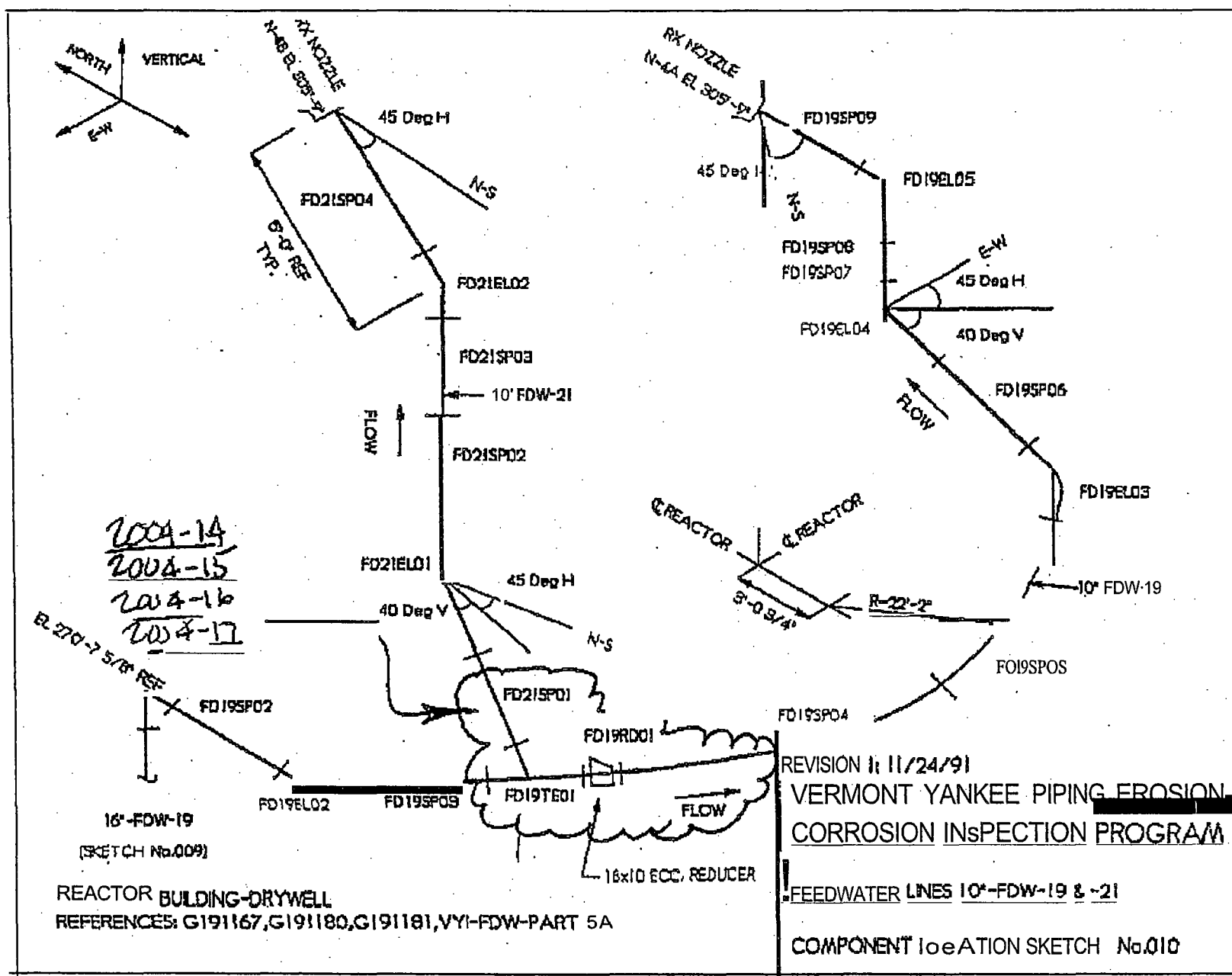


REVISION 4: 11124/91

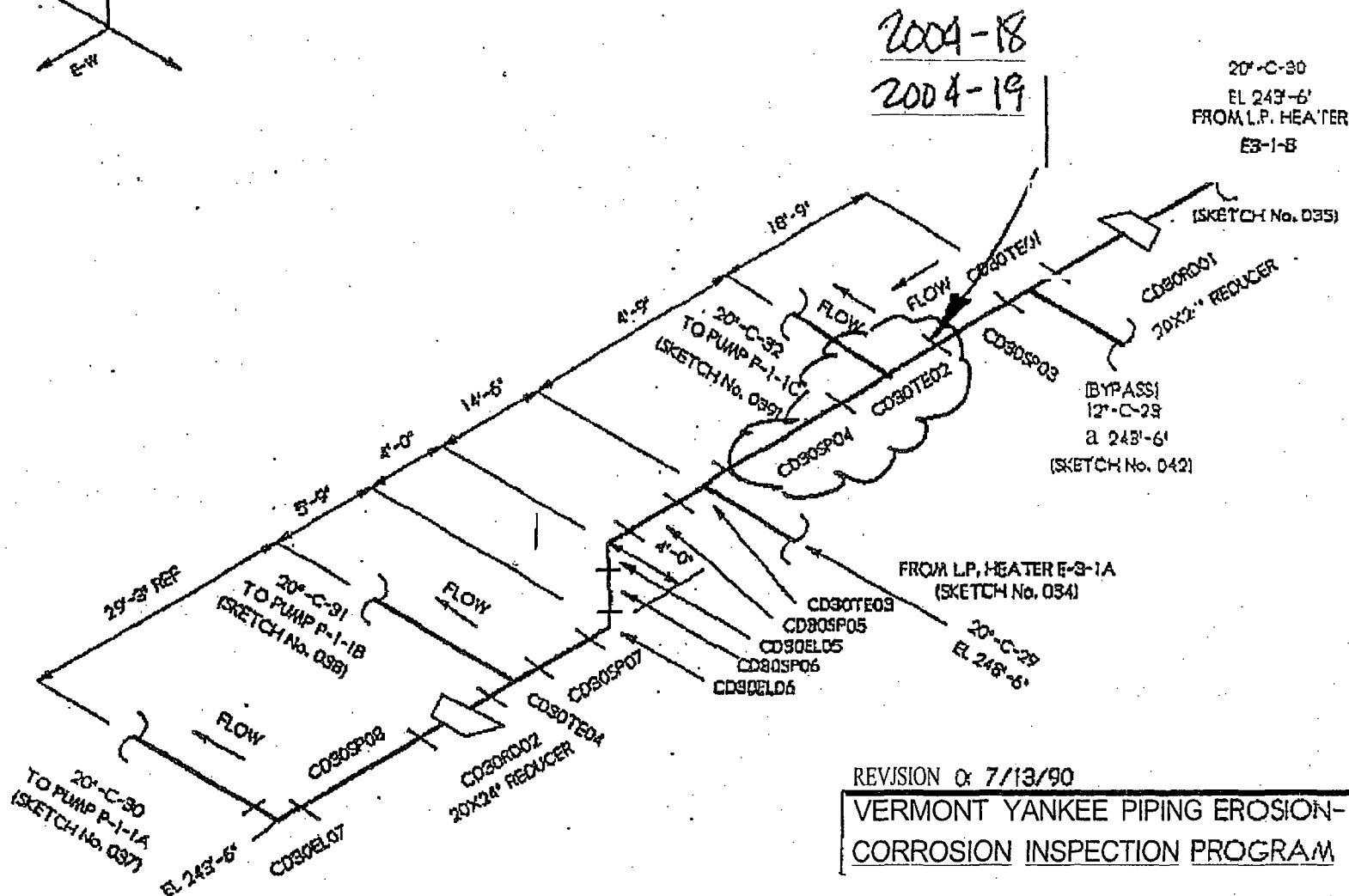
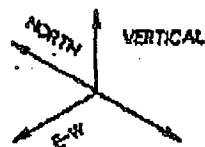
VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINES 16" FDW-14 & 16

COMPONENT LOCATION SKETCH No.Q09



NEC020208



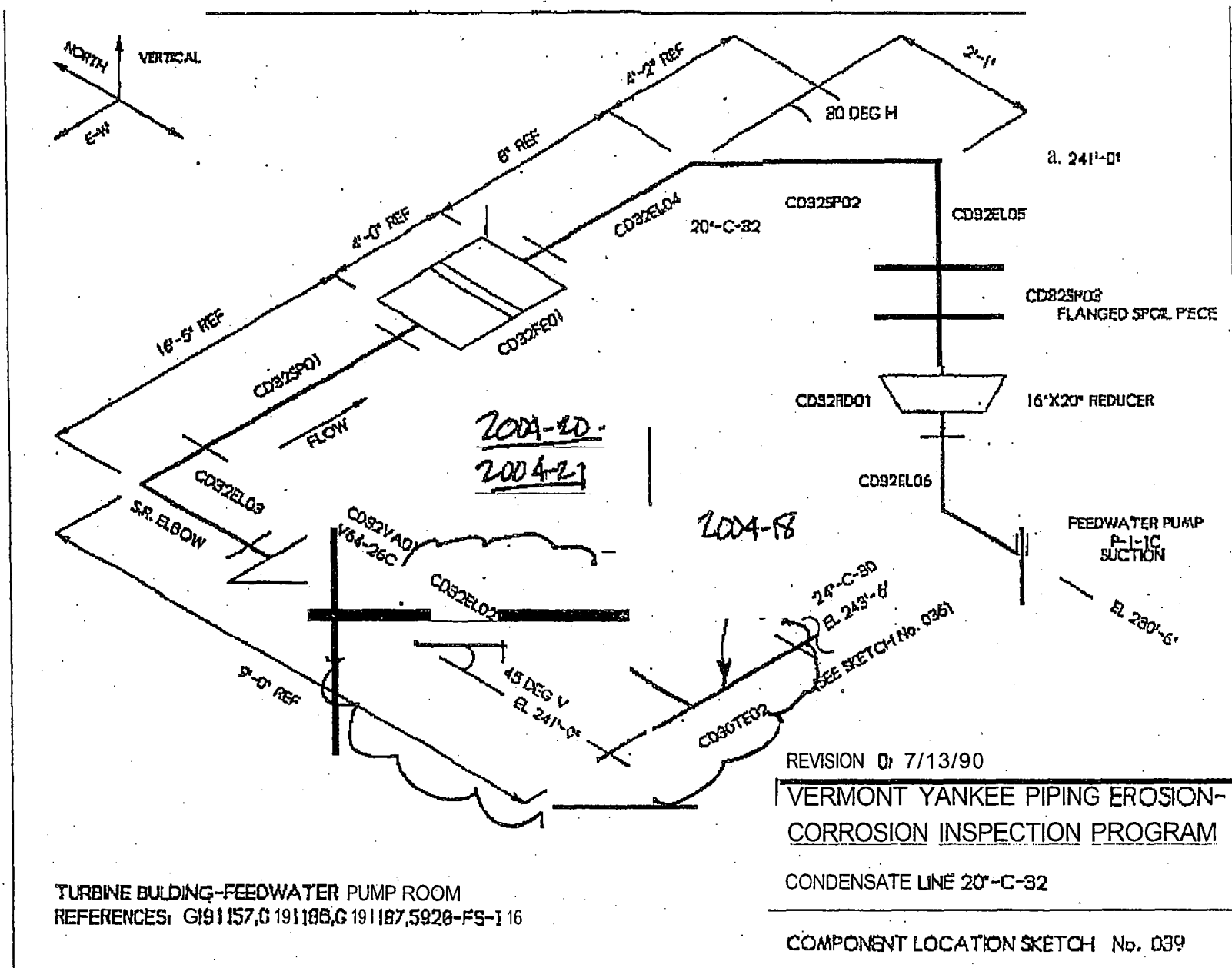
TURBINE BUILDING FEEDWATER PUMP ROOM  
REFERENCES: C191157, G1911811, 0191187, 5820-FS-116

REVISION 0: 7/13/90

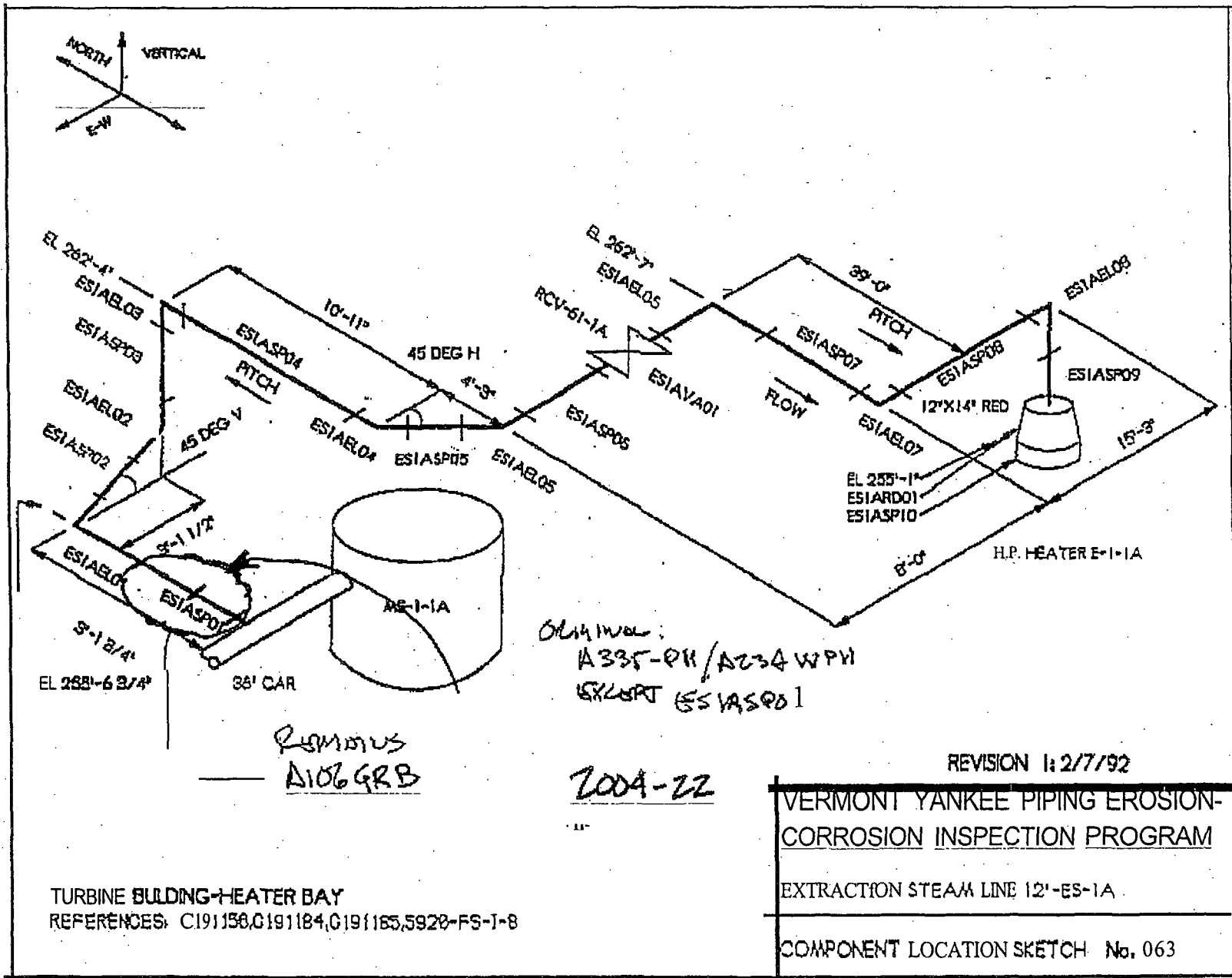
VERMONT YANKEE PIPING EROSION-  
CORROSION INSPECTION PROGRAM

CONDENSATE LINE 24"-C-30

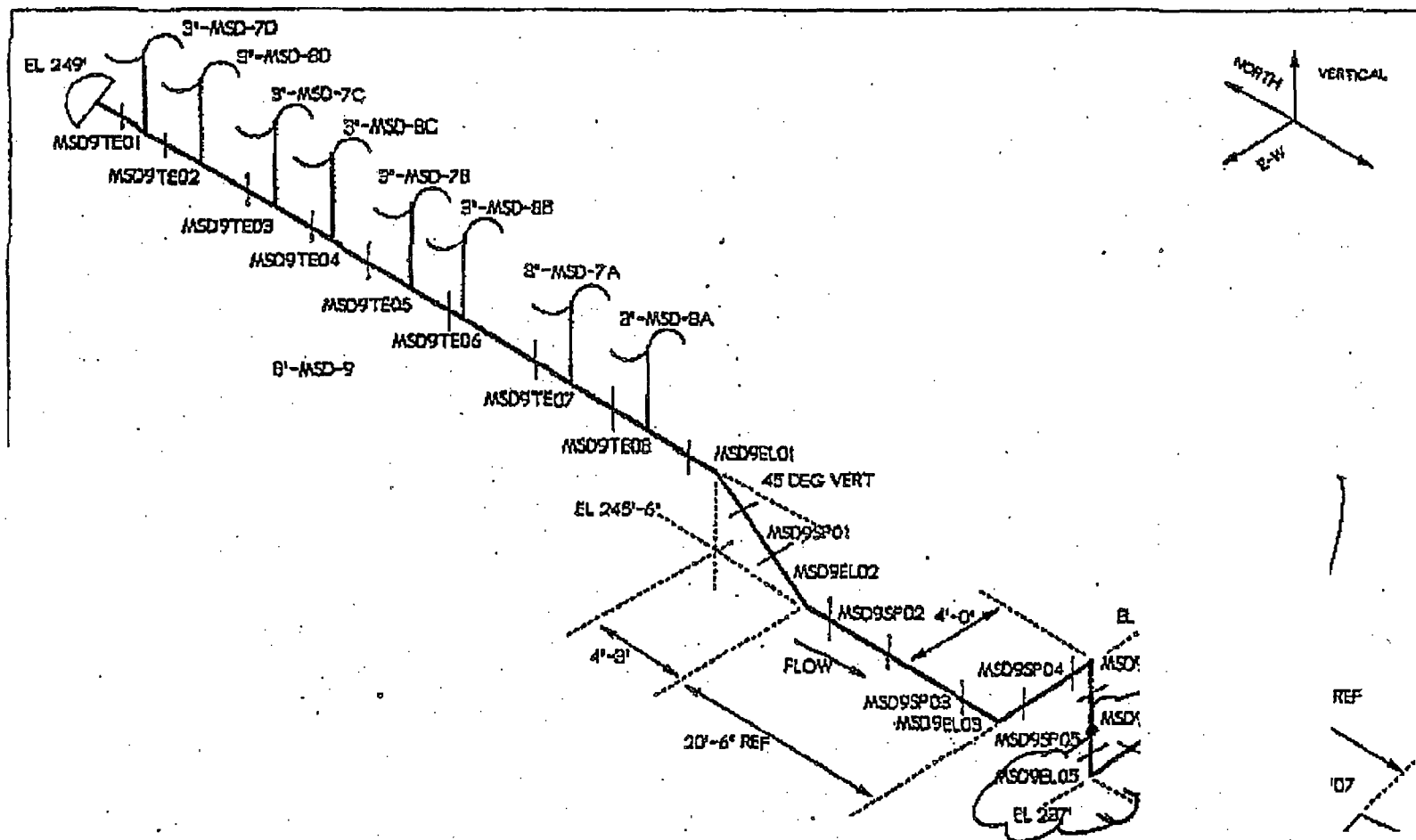
COMPONENT LOCATION SKETCH No. 096



NEC020210







TURBINE BUILDING-HEATER BAY

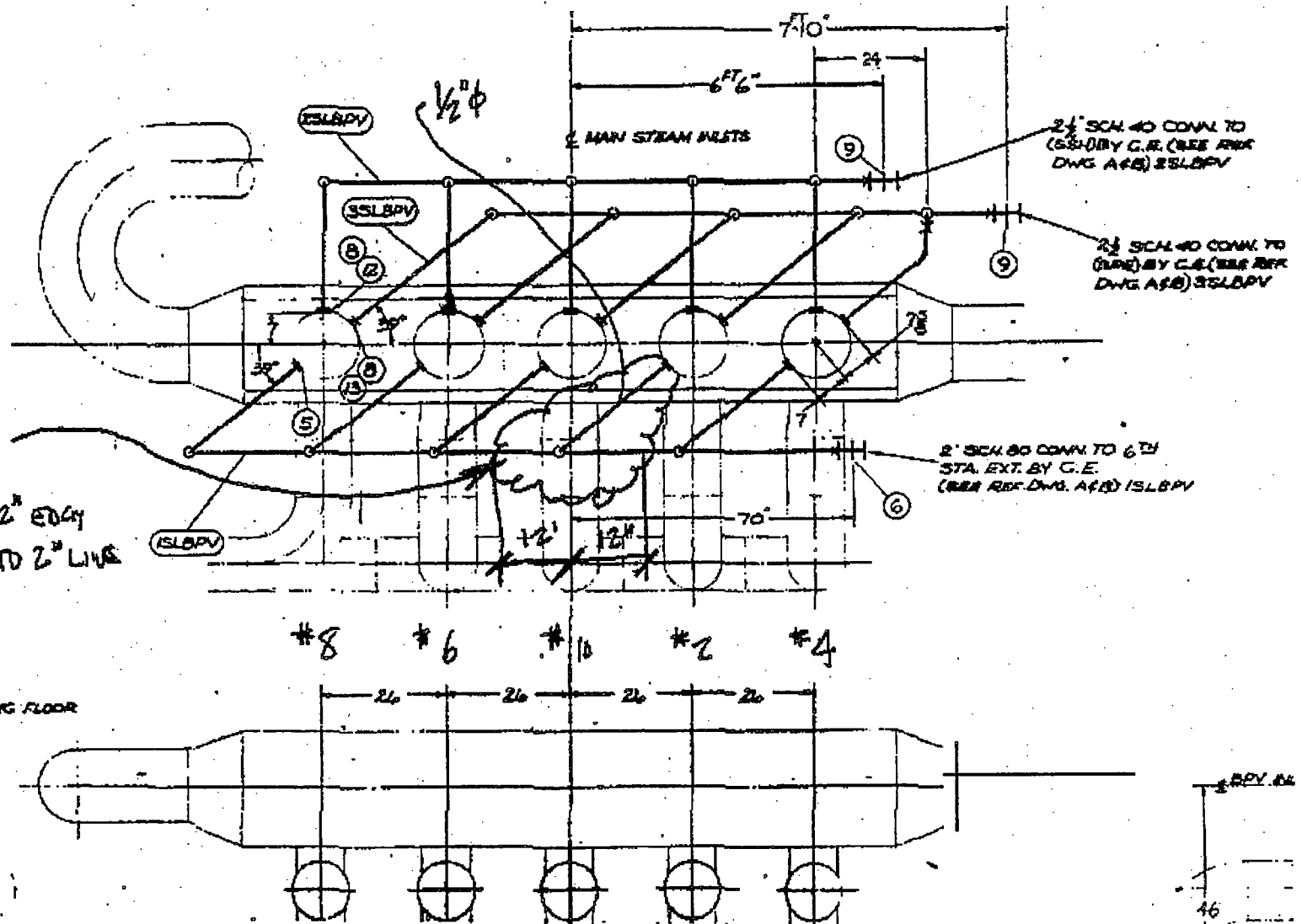
REFERENCES: G191156, G191182, G191183, 5928-FS-I-18

REF DWG 5920-1819



NORTH BYPASS  
VALVE CHEST

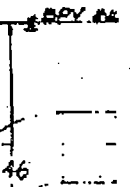
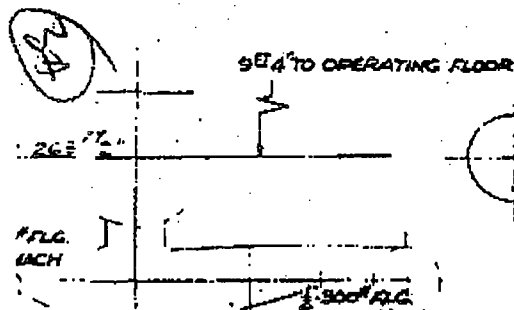
PLAN VIEW



2004 SMALL BOMS

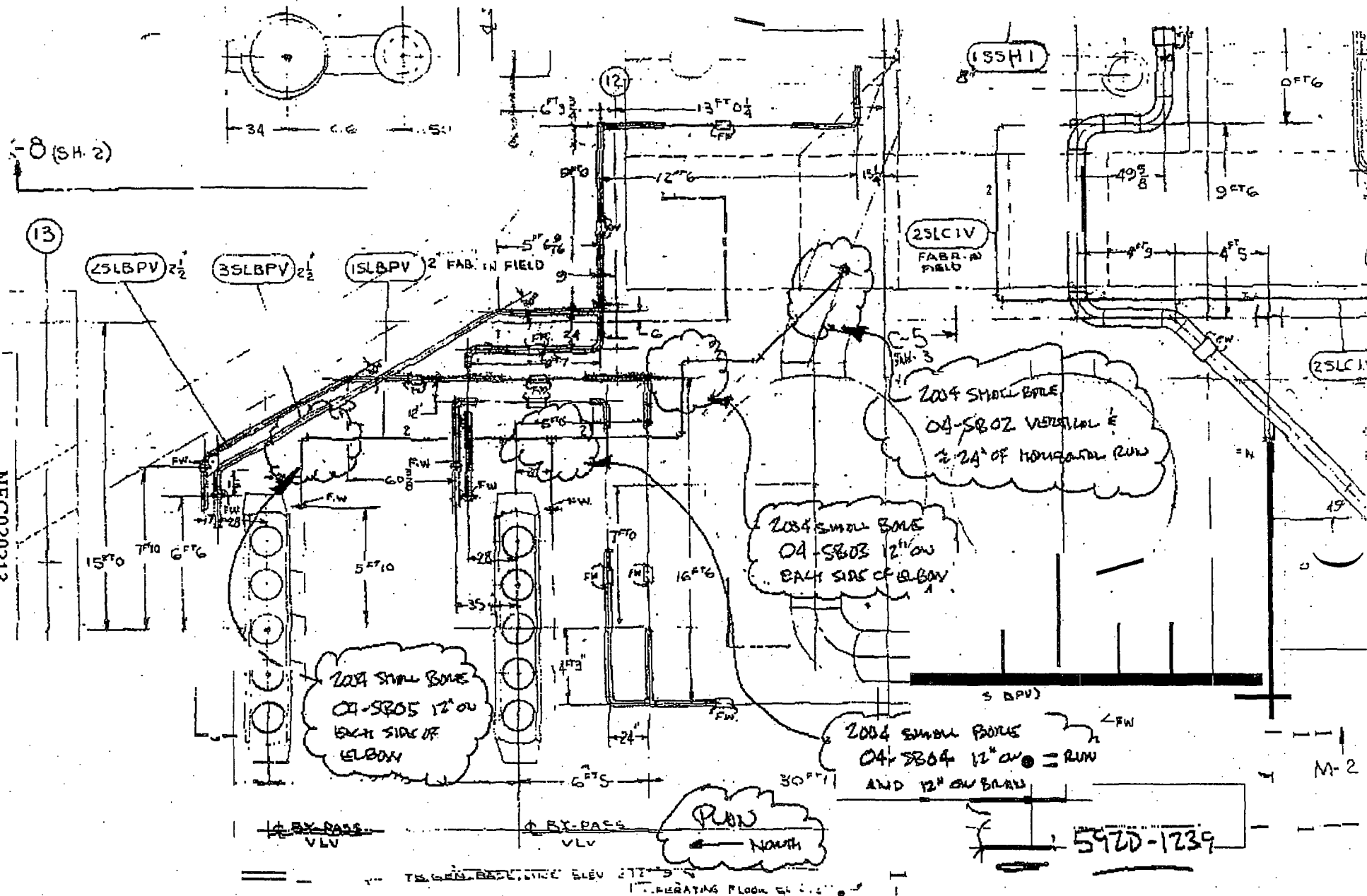
04-SB01

INSPECT 1/2" φ LINE & 12" EDGE  
SIDE OF CONNECTION TO 2" LINE



NEC020212

NEC020213



REF: 5920-1239

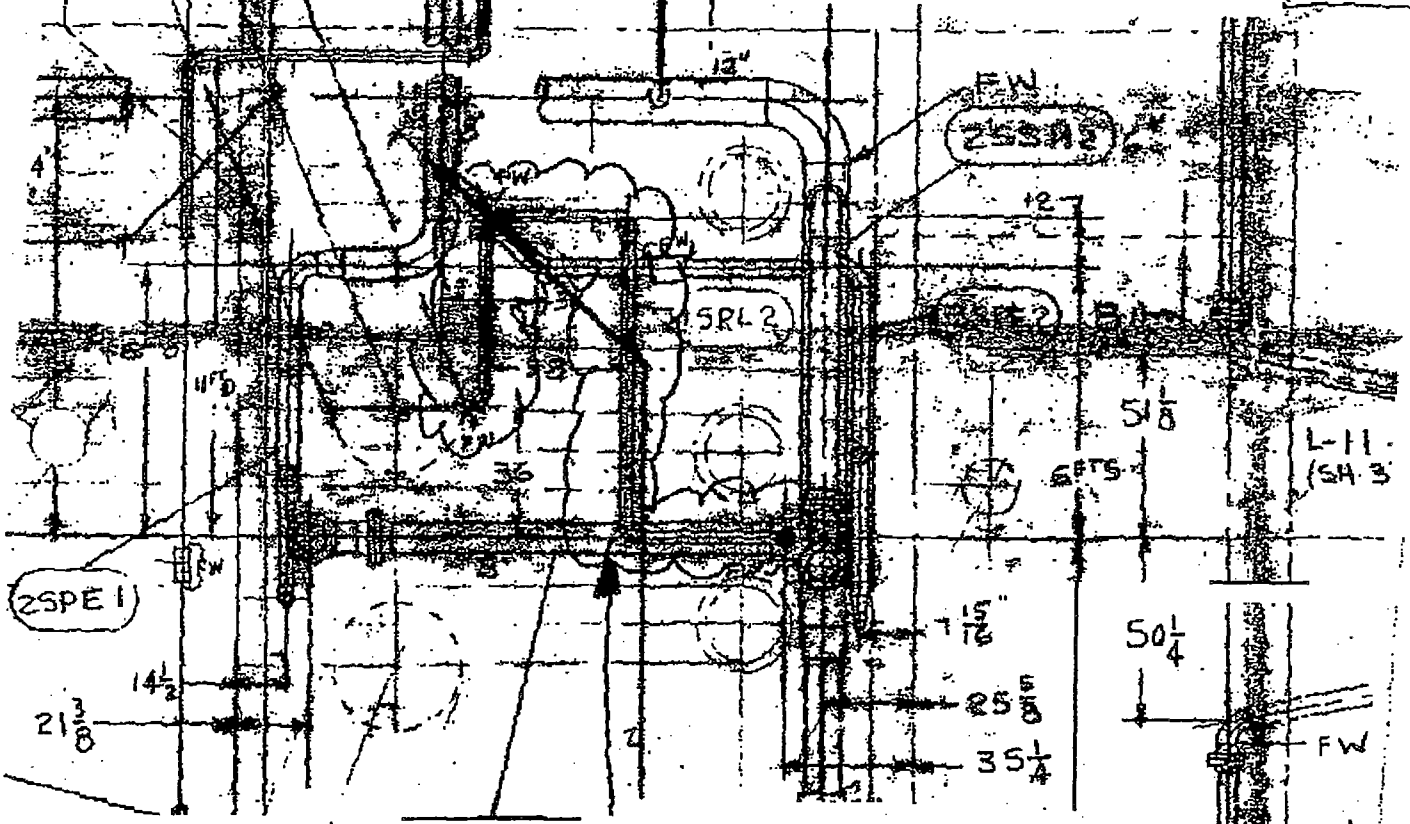
PLAN VIEW ← NORTH

04-SB06 TO 04-SB10  
ON LINE 2 1/2" ISRL2

255 THERMO  
WELL  
FOR TEMP.  
REC.  
EL. 258'-9 1/2"

PE 3

6 FT  
O E MACH



255PE1

L-11  
154.3

ISSH1  
8'

H.P. TURBINE DRAIN  
2 1/2" ISRL2

P4 10-3

255LCIV  
FABR-13  
FIELD

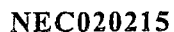
36

ISS

NEC020214

REF. 5920-1241

ELEVATION  
LOOKING  
SOUTH





NUCLEAR SERVICES DIVISION  
INSERVICE INSPECTION

PROCEDURE  
REVISION  
PAGE

YA-UT-11Z  
4  
6 of 6

PAGE 1023

THICKNESS DATA SHEET

DATA SHEET HD. UT-112-SB-021

PLANT VERMONT YANKEE OUTAGE Fall 1993

DRAWING 920-1239

REV. N/A

SYSTEM HP T-ASDR Drain COMPONENT/VELD HO. 93-SB-52

EH N/A

LOCATION TB 24

MATERIAL: CS PRODUCT FORM: Pipe APPROX. THICK.: .25"

INSTRUMENT: D-791-RM MAKE: Parameters MODEL: 36 DL Plus SERIAL NO.: 93129207

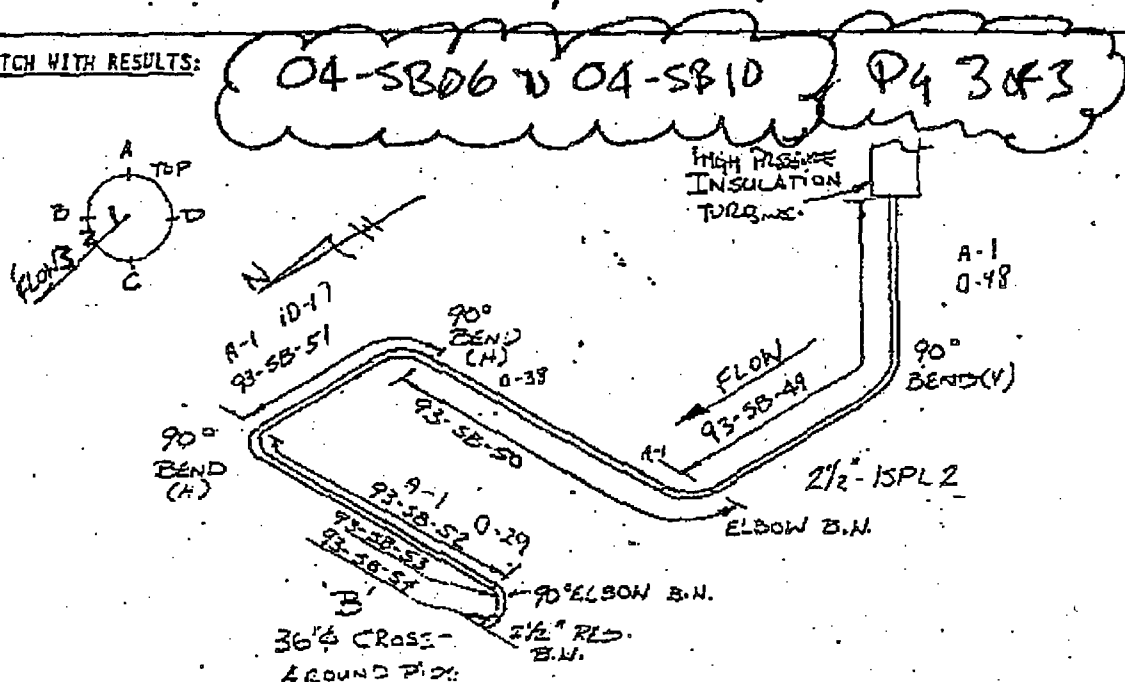
CAT ☐ DIGITAL ☒ HORIZONTAL LINEARITY PERFORMED ☐

TRANSDUCER MAKE/MODEL: Parameters MODE: ☒ PITCH/CATCH ☐ PULSE/ECHO FREQUENCY: 5.0 MHz SIZE: .312

CAL. BLOCK MATERIAL: CS 1/2" 93-6448 PRODUCT FORM: wrought THICKNESSES: 1.5"

CALIBRATION TIMES: INITIAL: 0900 CHECK: 1030 CHECK: N/A CHECK: N/A FINAL: 1200

SKETCH WITH RESULTS:



EXAMINER Jerry Mancy

EXAM AGENCY/CORRIGANT ENGINEER M. Tarrant

ISI COORDINATOR (Optional) [Signature]

QA (Optional)

AMT (Optional)

R6517

DATE 9-19-93

DATE 9/21/93

DATE 9/27/93

DATE

DATE

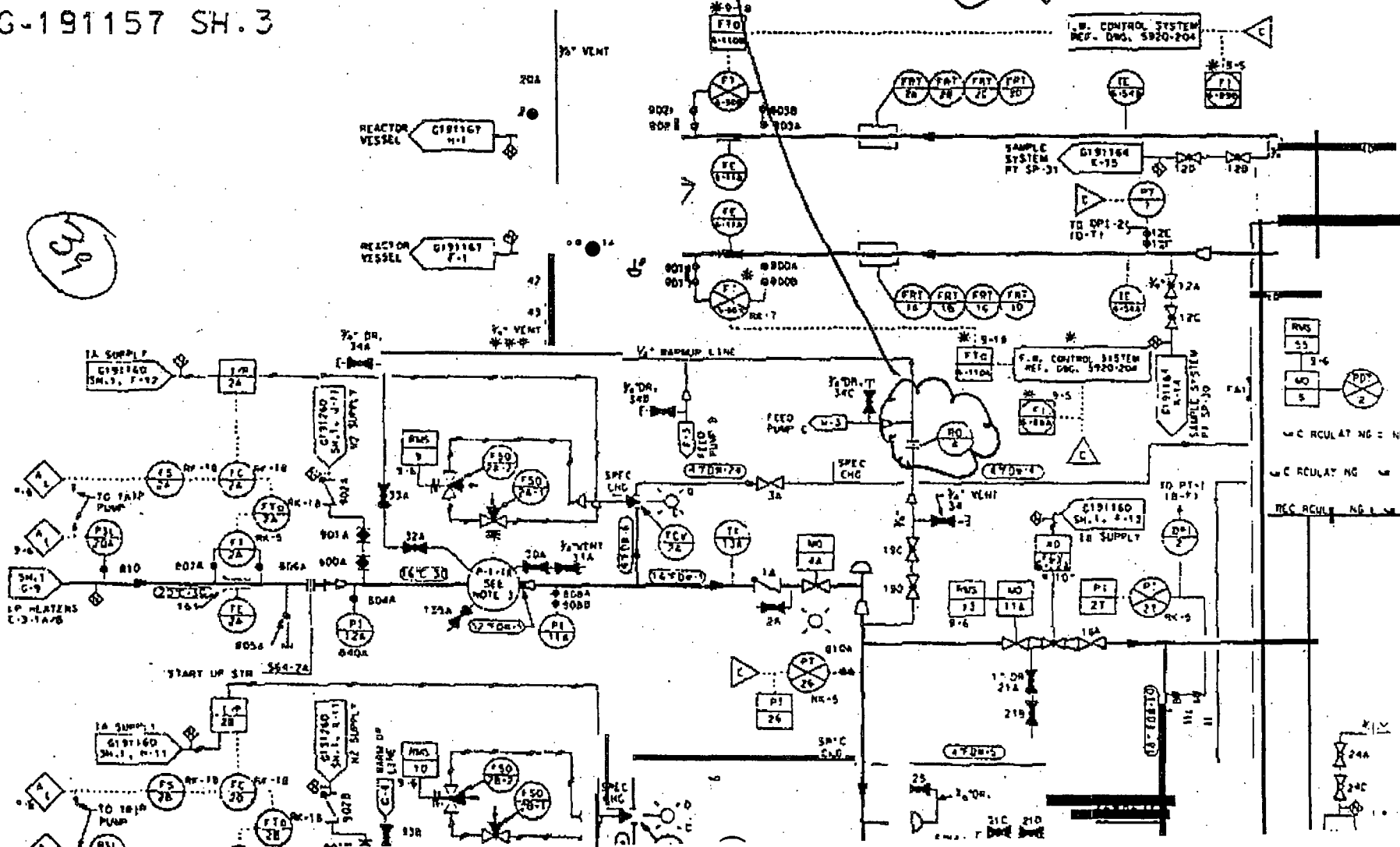
PREVIOUS INSPECTION DATA

REVIEWED: [Signature] 9/29/93

(38)

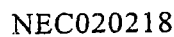


04-SB11 P4 ~~10-2~~



P4 20F2

04-SB11 (12" D.S. OF R.D.  
VENTILATOR IF WITHIN 12" OF R.D.)





# PP 7028 VY PIPING FLOW ACCELERATED CORROSION (FAC) INSPECTION PROGRAM

RFO 24 - SPRING 2004

Planned Scope  
Challenge MASTM  
3/18/03

## PLANNED SCOPE

- External Ultrasonic Thickness (UT) Inspection of 26 large bore components at 11 locations. Includes some new locations, some repeat inspections for trending, and for a baseline prior to power uprate.
- External Ultrasonic Thickness (UT) Inspection of 11 sections of small bore piping. Includes 5 sections on the turbine bypass valve 1<sup>st</sup> seal leakoff line if the line is not replaced during the outage.
- Internal Visual Inspection of 6 of the 8 Turbine Cross Around Lines (36A to 360, 30C, & 300).
- WO 02-4906 FAG Inspections -restraint removed with VYM 2003/009

## BASIS 1 COMMENTS

- Component selection based on previous inspection results, the CHECWORKS models, industry and plant operating experience, the FAC HWC study, postulated power uprate effects, and engineering judgment.
- Similar numbers of components to be inspected as in previous outages. VY inspects less than the industry average due to a simpler design (no reheat) and Chrome-Moly Extraction Steam piping.
- For Large Bore Piping: The combination of previous inspections and the proposed 2004 inspections should provide a solid basis for a high degree of confidence against unexpected piping wall loss. We will have sufficient base line data to evaluate any negative trends from Power Uprate and HWC.
- Recent Small Bore leaks at VY and numerous ones at other plants require an increased and more intelligent focus on small bore piping.
- Given that it's a full year from the start of the outage, any industry or plant events that occur in the interim or new information may necessitate an increase in the planned scope.

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